BAYTEX ENERGY TRUST

2003 ANNUAL REPORT

IT'S A MATTER OF TRUST

TABLE OF CONTENTS

CORPORATE PROFILE

Baytex Energy Trust ("Baytex") is a Calgary-based energy income trust created though the reorganization of Baytex Energy Ltd. in September 2003. Baytex is engaged in the development, acquisition and production of oil and natural gas in the Western Canadian Sedimentary Basin.

The base of operations includes a high-quality portfolio of operated properties and development prospects with considerable upside potential. During 2003, the oil and gas assets associated with the Trust generated average production of 35,000 boe per day comprised of approximately 73 percent oil and 27 percent natural gas. Baytex plans to maintain its production and reserve base through internal property development and the selective acquisition of complementary assets within its core operating areas.

Baytex is focused on delivering consistent returns to unitholders through prudent operational and financial management. Baytex is traded on the Toronto Stock Exchange under the symbol BTE.UN.

TRUST

Trust is about being honest, transparent and acting with integrity. Trust takes time to develop and requires an investment. It is tough to get but easy to lose. A company that is consistently open and honest builds believability and trust. At the centre of trust is reliability. It's about keeping agreements and walking the talk. It is doing what you say you're going to do. Trust is the foundation of leadership. With high trust, high performance ensues. With Baytex's conversion to an energy trust in September 2003, we aspire to all of this and more. As we establish our track record as an energy trust, our goal is to build the foundation of trust by delivering consistent performance.

PREDICTABILITY

Trust is certainty based on past knowledge or experience. It's knowing that a boomerang will return - even without first-hand experience. As a recently formed energy trust, our objective in terms of our distributions is to build that same level of predictability for our unitholders.

Trust is about being honest, transparent and acting with integrity. Trust takes time to develop and requires an investment. It is tough to get but easy to lose. A company that is consistently open and honest builds believability and trust. At the centre of trust is reliability. It's about keeping agreements and walking the talk. It is doing what you say you're going to do. Trust is the foundation of leadership. With high trust, high performance ensues. With Baytex's conversion to an energy trust in September 2003, we aspire to all of this and more. As we establish our track record as an energy trust, our goal is to build the foundation of trust by delivering consistent performance.

TEAMWORK

Trust is having complete confidence in a person or plan; it's knowing that you can rely on someone or something when it really counts. Baytex had a 10-year track record of successful operations prior to its conversion to an energy trust. It's because of this history that we know our assets, we know heavy oil and we know how to generate superior returns.

Trust is about being honest, transparent and acting with integrity. Trust takes time to develop and requires an investment. It is tough to get but easy to lose. A company that is consistently open and honest builds believability and trust. At the centre of trust is reliability. It's about keeping agreements and walking the talk. It is doing what you say you're going to do. Trust is the foundation of leadership. With high trust, high performance ensues. With Baytex's conversion to an energy trust in September 2003, we aspire to all of this and more. As we establish our track record as an energy trust, our goal is to build the foundation of trust by delivering consistent performance.

LEADERSHIP

Trust is believing in the integrity and reliability of others. The leadership team at Baytex Energy Trust is committed to acting in the best long-term economic interests of our unitholders. Our direction is clear as we work to deliver consistent returns through prudent financial and operational management.

Trust is about being honest, transparent and acting with integrity. Trust takes time to develop and requires an investment. It is tough to get but easy to lose. A company that is consistently open and honest builds believability and trust. At the centre of trust is reliability. It's about keeping agreements and walking the talk. It is doing what you say you're going to do. Trust is the foundation of leadership. With high trust, high performance ensues. With Baytex's conversion to an energy trust in September 2003, we aspire to all of this and more. As we establish our track record as an energy trust, our goal is to build the foundation of trust by delivering consistent performance.

HIGHLIGHTS

Baytex Energy Trust commenced operations as an oil and gas income trust on September 2, 2003. As the Trust is the successor organization to Baytex Energy Ltd., results of the current period may not be entirely comparable to those of the prior period as certain assets were transferred out of Baytex pursuant to the Plan of Arrangement effective September 2, 2003.

Financial *($ thousands, except per share data)*	2003	2002
Petroleum and natural gas sales	**351,404**	365,860
Cash flow from operations[1]	**138,233**	191,086
Per unit/share – basic	**2.49**	3.65
– diluted	**2.45**	3.59
Cash distributions paid or declared	**33,382**	–
Per unit	**0.60**	–
Net income	**38,138**	45,136
Per unit/share – basic	**0.69**	0.86
– diluted	**0.67**	0.85
Net capital expenditures	**49,263**	126,468
Total net debt	**213,572**	362,775
Weighted Average Trust units/shares outstanding at December 31 (thousands)		
Basic	**55,530**	52,819
Diluted	**56,520**	57,945
Operating		
Production		
Light oil and NGLs (bbls/d)	**2,273**	3,154
Heavy oil (bbls/d)	**23,911**	23,967
Total oil and NGLs (bbls/d)	**26,184**	27,121
Natural gas (mmcf/d)	**63.0**	72.6
Barrels of oil equivalent (boe/d @ 6:1)	**36,686**	39,214
Reserves, proved and probable[2]		
Oil and NGLs (mbbls)	**88,517**	130,221
Natural gas (mmcf)	**106,300**	89,094
Barrels of oil equivalent (mboe @ 6:1)	**106,234**	145,070

(1) Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other operating items. The Trust's cash flow from operations may not be comparable to other companies. The Trust considers cash flow a key measure of performance as it demonstrates the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

(2) Reserves information as at December 31, 2002 is prepared in accordance with National Policy 2-B. Probable reserves as at December 31, 2002 represents 50 percent of the total probable reserves then assigned to allow more appropriate comparison with probable reserves under NI 51-101 as at January 1, 2004.

DELIVERING

2003 was an eventful, productive and ultimately profitable year for Baytex and its stakeholders. After 10 years as an exploration and production company, growing our operations from scratch to 40,000 boe per day, Baytex was transformed into an income trust to maximize shareholder value. This strategy was rewarded with great success, as shareholders realized a 50 percent total return on investment during the year, with the price of Baytex trust units, cash distributions declared during 2003 and the price of Crew Energy common shares all included in the calculation.

The conversion of Baytex into an income trust was a complicated financial and corporate undertaking. It began in late 2002 when a long-term crude oil supply contract was signed to remove the majority of the heavy oil differential volatility affecting our production revenue. Our second step was the disposition of a major natural gas asset in March 2003 to install necessary financial strength to the balance sheet. Next came the redemption of the senior secured notes and the exchange of senior subordinated notes in the spring and early summer in order to create a capital structure that would facilitate the operations of an income trust. Finally, a Plan of Arrangement was approved by the shareholders and Baytex Energy Trust became a reality in September.

We believe that Baytex possesses the necessary competitive advantage to be successful in the income trust sector. The traditional oil and gas income trust model in Canada has been one that relies on acquisitions to sustain or grow its production and asset base. During our years as an exploration and production company, Baytex accumulated a large property inventory, particularly in heavy oil, which can be drawn upon to sustain our production and reserve base. With the ever expanding oil and gas income trust sector and the accompanying intense competition for acquisition opportunities, it is a distinct advantage if we do not have to principally rely on acquisitions to sustain our operations. Furthermore, our niche as a heavy oil specialist should provide us with better opportunities to augment our asset base with selective acquisitions.

ON TRUST

Operationally, we had a very active and successful year. We drilled 243.4 net wells with a 92.6 percent success rate. Production during the year averaged approximately 35,000 boe per day, excluding production from the properties transferred to Crew and production from the properties in Ferrier that were sold. We replaced production by 164 percent, completely replenished our proved developed producing reserves and achieved finding and development costs of $7.62 per boe before reserves revisions. Our capital program was predominantly internal exploitation and development with only four percent of the total capital expenditures spent on acquisitions.

Significant expenditures were incurred in 2003 to enhance Baytex's position in areas of future development, with approximately $20 million spent on land and seismic during the year. In the Seal area of Alberta, currently one of the most active areas for heavy oil development in the Western Canadian Sedimentary Basin, Baytex has accumulated 58 sections of prospective land at 100 percent working interest, of which 44 sections were acquired in 2003. Baytex has designed a program in 2004 to test the oil quality and productivity of various prospects on its lands in Seal. The results of this program will help set the plans for large-scale development in this area in the coming years. Baytex has established a 2004 capital budget between $100 million and $110 million for the development of its existing properties, with the target of maintaining production at levels similar to those of 2003.

Financially, the story of the year was certainly the increasing strength of the Canadian dollar, which began the year at US$0.6331 and ended the year at US$0.7737. The overall impact on Baytex was less than most other companies in our industry as we have all of our debt denominated in U.S. dollars, thus providing an offsetting hedge against the reduction in cash flow. We incurred nearly $34 million of oil hedging losses in the year from WTI contracts on 15,000 barrels per day collared at US$26.50, and from another 2,500 barrels per day of heavy oil fixed price contract at below C$14.00. All of these contracts came to an end on December 31. We ended 2003 in an excellent financial position. After completing the Trust's first equity issue of 6.5 million units in December, we had $54 million of cash on deposit at year-end. Combined with our conservative cash flow retention and undrawn credit facilities of $165 million, we have the resources to fund our distributions and capital spending comfortably over the next two to three years.

In the second half of 2003, the Canadian Securities Administrators mandated new standards of disclosure for oil and gas activities referred to as National Instrument or NI 51-101. The requirements of NI 51-101 have been well documented and discussed in our industry over the last few months. In considering the possible impact of these new standards on our reserves, Baytex's Board of Directors also decided to appoint one of the leading engineering firms in our industry, Sproule Associates Limited, to be our new independent reserves evaluators.

The Sproule Report, prepared in accordance with NI 51-101, reflected the differences in reserves assignments under the new standards. While Baytex's non-heavy oil reserves were revised upward by 9.2 percent, our heavy oil reserves were revised downward by 38.9 percent. Overall total proved plus probable reserves at year-end 2003 were 26.7 percent lower than the established reserves of one year ago. The reduction was entirely on heavy oil reserves, as the new standards caused recovery factors to be lowered and future drilling locations to be reduced. Also, as Baytex's future capital programs under the structure of an income trust are reduced and more evenly distributed compared to previous plans under a growth-oriented exploration and production

company, reserves assignments are curtailed under the new standards. As we continue with our development plans on our assets, additional reserves could be recognized under the new disclosure standards. The vast heavy oil resources underlying our asset base are estimated by Baytex to be in excess of one billion barrels of oil in place. Technological improvement and production performance over time may increase future recovery factors, which could add significant realizable reserves to the existing properties of the Trust.

The results of the Sproule Report illustrate the key merits of our trust:

(1) Our organic ability to replace produced-out reserves. Proved developed producing reserves were maintained at prior year levels through our drilling programs, thus validating our business strategy to focus on internal property development to sustain our operations.

(2) Our trading price to net asset value ratio is one of the most conservative in our sector.

(3) The full potential of our assets is not reflected in the Sproule Report. Under the stringent requirements of NI 51-101, no reserves have been recognized for some of our undeveloped, yet high potential assets, such as our undrilled acreages in Ardmore-Cold Lake and Seal. This is a unique characteristic of our asset base as most oil and gas income trusts are generally comprised of mature producing assets. We hope the full potential of our asset base can be recognized over time with our prudent development plans.

Notwithstanding the revisions in the Sproule Report, our business plans and 2004 targets have not changed. Proved developed producing reserves have been maintained at prior year levels, which bodes well for our plan to maintain production at 2003 levels. Our current distribution of $0.15 per month is estimated to be within our target range of 60 percent to 70 percent of cash flow, and we plan to maintain this distribution absent of any significant changes to commodity prices or production.

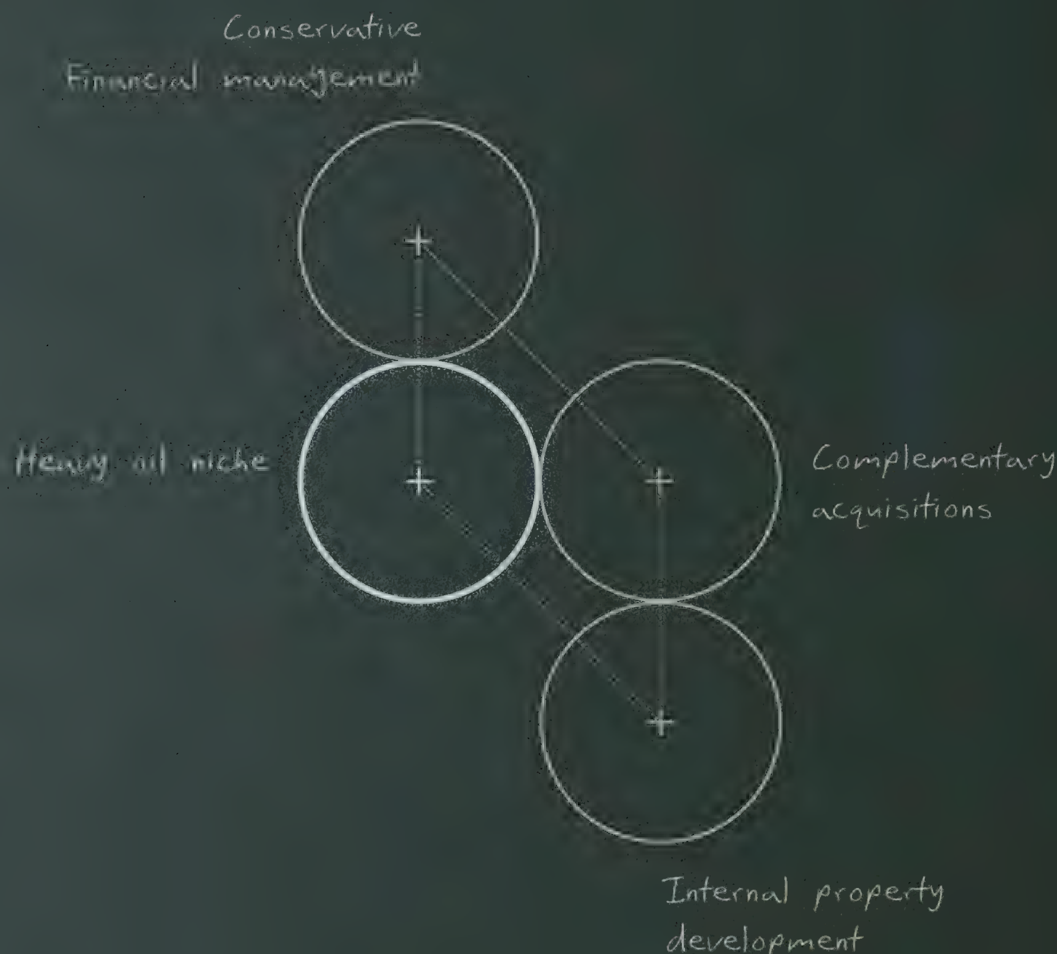
We are pleased with our accomplishments in 2003 and excited about our prospects in 2004. We are well positioned operationally and financially. Prevailing commodity prices and interest rates should provide a favourable environment for income trusts to compete for investors' considerations. We are confident that we can continue to deliver superior returns to our unitholders.

On behalf of the Board of Directors

Raymond T. Chan, CA
President and Chief Executive Officer
Baytex Energy Ltd.
March 10, 2004

DELIVERING

OUR BUSINESS STRATEGY



SUSTAINABLE RETURNS

Baytex's business strategy is designed to maintain the long-term viability of the Trust while at the same time maintain a level of consistency in performance. The following represents the four corners of Baytex's business strategy:

Conservative financial management (+)

Baytex's distributions represent 60 to 70 percent of operating cash flow which is one of the lowest payout ratios in the oil and gas trust sector. This strategy ensures that Baytex has sufficient capital to develop its vast inventory of internally generated drilling projects. Baytex enjoys one of the strongest balance sheets in the oil and gas trust sector with all of its borrowings under US$ denominated long-term notes. Baytex also has undrawn bank credit facilities totalling $165 million coupled with $53.7 million in cash at year-end 2003.

Heavy oil niche (+)

Baytex's heavy oil assets allow for low drilling risk and predictable production management. Baytex has drilled over 700 heavy oil wells since 1999 with a 94 percent success rate. The lower cost structure of heavy oil also contributes to better investment efficiency.

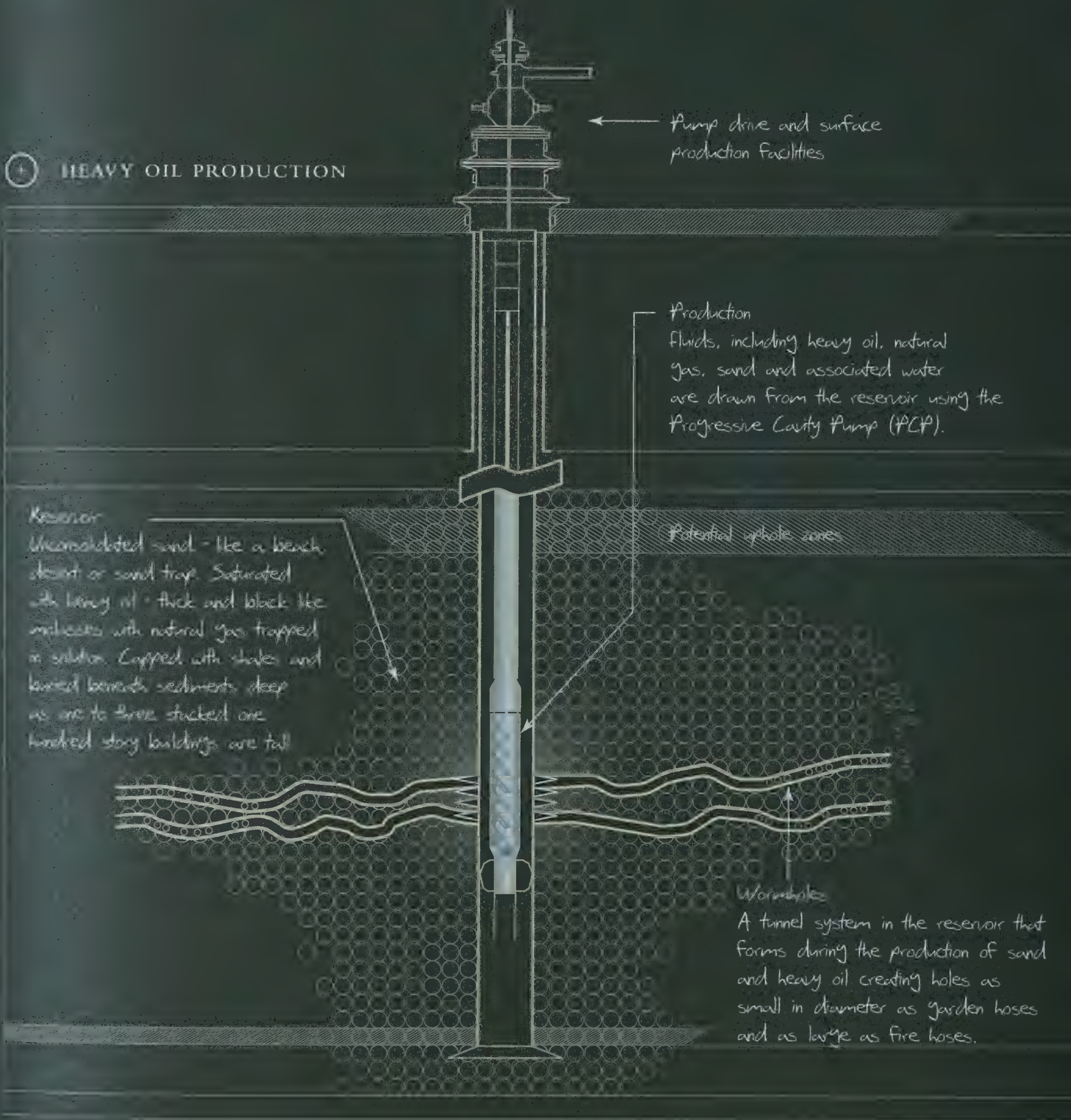
(+) Complementary acquisitions

In addition to Baytex's existing high-quality assets and drilling prospects, Baytex has a highly skilled and active acquisition team with a mandate to identify and execute acquisition opportunities that are complementary to Baytex's existing asset base. Baytex does not rely on acquisitions to replace reserves and production; however, the Trust possesses the skills and financial strength to compete for acquisitions, particularly in its core operating areas.

(+) Internal property development

Baytex possesses a vast inventory of internal development prospects in both its heavy and conventional districts. The ability to develop properties internally allows Baytex to better control the cost and timing of its capital investments.

4 HEAVY OIL PRODUCTION



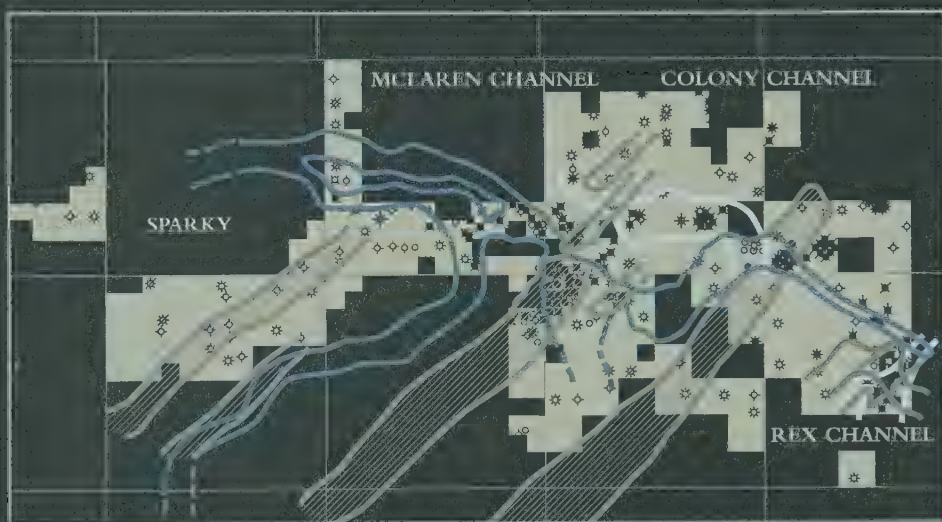
The Market

Heavy oil is used to produce road asphalt, roofing tar, heavy fuel oils and lubricants. Refineries with heavy oil upgrading capabilities can convert it into light oil and further refining results in gasoline, diesel, jet fuel and other higher\grade petroleum products.

HEAVY OIL DISTRICT

ARDMORE AND COLD LAKE

+ Primary production using vertical and slant drilling/production technology
+ Oil quality is 11 to 13 API

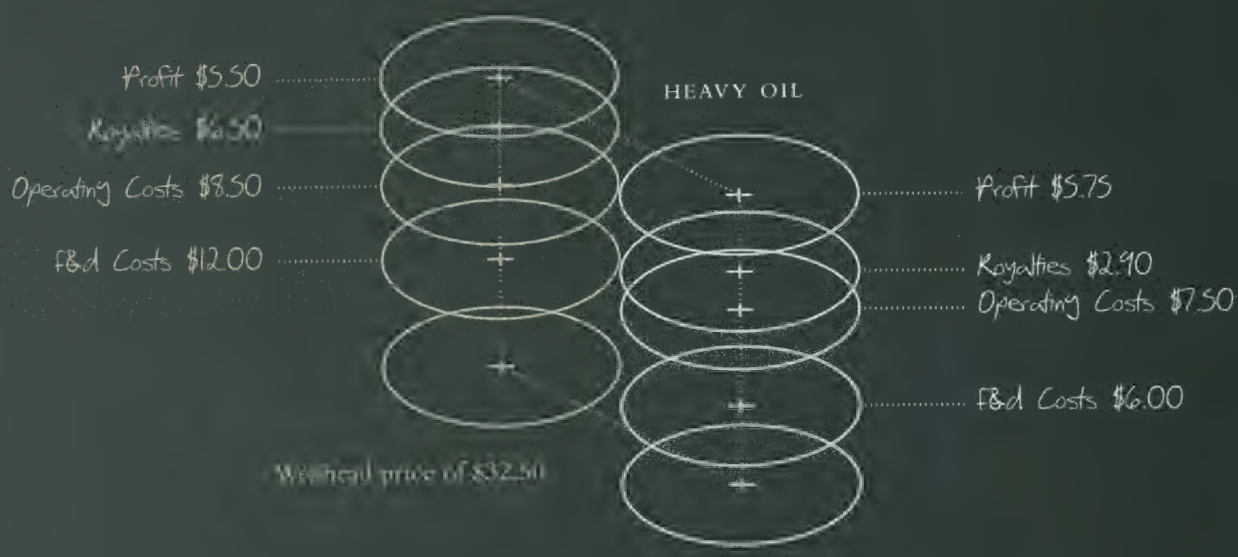


SEAL

+ Major prospective area for Baytex
+ Test wells drilled during Q1/04
+ Strategic land position of 58 sections

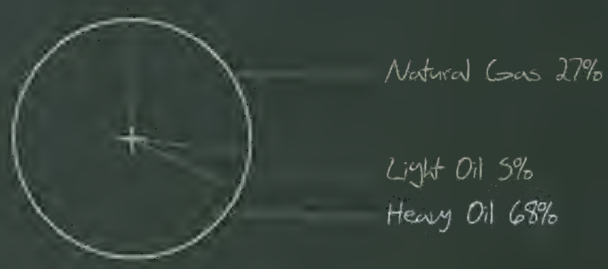
- LAND
- MCLAREN CHANNEL
- COLONY CHANNEL
- SPARKY
- REX CHANNEL
- Q1/04 DRILLING LOCATIONS
- PIPELINES

COMMODITY COMPARISON ANALYSIS



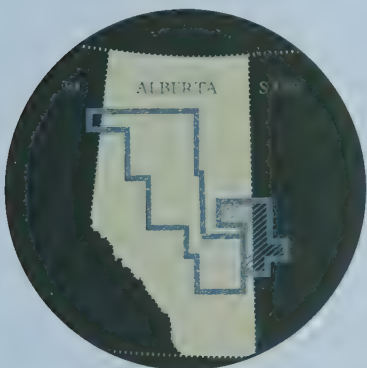
Wellhead price of $22.15

PRODUCTION PROFILE



Based on average production of 35,000 boe/d during 2003

PRINCIPAL PROPERTIES



For the year ended December 31, 2003, Baytex participated in the drilling of 266 (243.4 net) wells, resulting in 173 (158.9 net) oil wells, 67 (61.4 net) gas wells, seven (5.1 net) service wells and 19 (18.0 net) dry holes. The overall success rate for the year was 92.9 percent (92.6 percent net).

Total capital spending for the year was $186.7 million, including $180.1 million on exploration and development and $6.6 million on acquisitions. Excluding spending in the Ferrier area, the assets of which were sold in March 2003, and spending on the properties which were transferred to Crew Energy Inc. at the end of August 2003, capital expenditures on the Trust's assets were $159.3 million during 2003. This program yielded excellent results as it replaced 164 percent of production and maintained the Trust's proved developed producing reserves at prior year levels. Finding and development costs of this program were $7.62 per boe of proved plus probable reserves before revisions and $11.26 per boe of proved reserves before revisions.

PRINCIPAL PROPERTIES

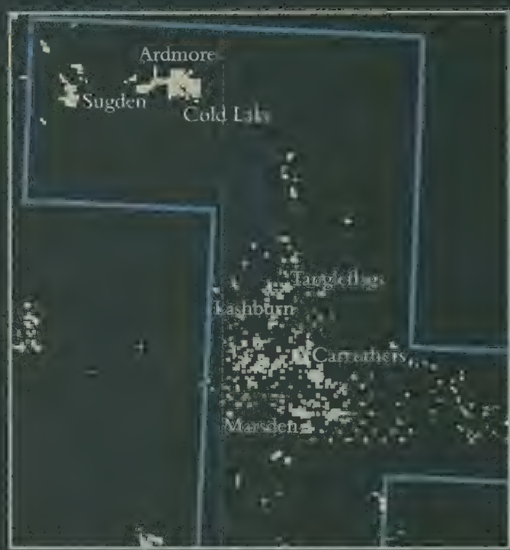
Baytex's major crude oil and natural gas properties are located within two operating areas – the Heavy Oil District and the Conventional Oil and Gas District. Each district constitutes a balanced portfolio of operated properties and development prospects with considerable upside potential. Baytex has established skilled technical teams to operate each district. Each team has a mandate to apply its specific knowledge and expertise to its operating area. This focused approach aids in the evaluation of exploration, development and acquisition opportunities and improves cost efficiency.

Heavy Oil District

The Heavy Oil District accounts for approximately two-thirds of Baytex's current production and approximately three-quarters of reserves. Heavy oil operations consist of cold conventional production from wells with multi-zone potential. Production is generated primarily from vertical, slant and horizontal wells using progressive cavity pump

CORE AREAS OF OPERATION

CONVENTIONAL OIL AND GAS DISTRICT



HEAVY OIL DISTRICT

technology to generate large volumes of heavy oil combined with sand. Production from these wells usually averages between 40 and 100 barrels per day of low gravity crude ranging from 12 to 18 API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States for upgrading into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt.

During 2003, production in the Heavy Oil District averaged 25,676 boe per day made up of 23,911 barrels per day of heavy oil and 10.6 million cubic feet per day of natural gas. The Trust drilled 174 gross (165.2 net) wells in the district, resulting in 159 gross (150.2 net) oil wells, four gas wells, four service wells, and seven dry and abandoned wells for a success rate of 96 percent.

Baytex possesses a vast inventory of development projects in the west central Saskatchewan heavy oil region and the Cold Lake, Ardmore and Seal areas of north central Alberta. The ability to generate replacement production organically allows Baytex to better control the cost and timing of its capital investments.

Baytex will continue to build value through internal property development and selective acquisitions. Future heavy oil activity will focus on the development of the Seal and Ardmore properties along with continued infill drilling at adjacent Cold Lake and throughout the Saskatchewan properties.

Alberta Heavy Oil Properties

Ardmore Ardmore is one of the key heavy oil development and production areas for Baytex. Acquired in 2002, this year-round access area generated approximately 3,100 barrels of oil per day in 2003, with current production in excess of 4,500 barrels per day. Since acquiring this property, Baytex has applied leading-edge heavy oil drilling and production technology to improve production and reduce cost. Wells in the area are 100 percent operated by Baytex and they are able to produce up to 300 barrels per day of 11 to 13 API heavy crude oil from the Mclaren and Sparky formations. Baytex drilled 48 gross (47.6 net) oil wells in the area during 2003, resulting in 47 gross (46.6 net) oil wells and one service well. Baytex currently holds approximately 32,000 net acres of 100 percent working interest undeveloped land in the Ardmore area.

Cold Lake Baytex acquired the Cold Lake heavy oil property in 2001. This year-round drilling area is located on Cold Lake First Nations lands with heavy oil production generated largely from the Colony formation. Average production was 935 barrels per day during 2003. Baytex drilled 15 gross (13.5 net) operated oil wells in the Cold Lake area during 2003 and currently holds approximately 19,500 net acres of undeveloped land in this area.

Seal The Seal property is a highly prospective heavy oil area for Baytex. The property is located in the Peace River oilsands area of northwest Alberta. Baytex holds 100 percent working interests in approximately 58 sections of land of which 44 sections were acquired in 2003. The Seal oil deposits can be produced through horizontal wells using primary production technology without the use of capital intensive steam injection methods. Baytex completed a seven-well test program during the first quarter of 2004. A development plan for commercial production is being designed for the second half of 2004 and the winter of 2005.

Saskatchewan Heavy Oil Properties

Tangleflags Baytex acquired the Tangleflags property through the acquisition of Bellator Exploration Inc. in 2000. Tangleflags is characterized by multiple-zone reservoirs with production from the Colony, McLaren, Waseca, Sparky, General Petroleum and Lloydminster formations. Provincial government regulations generally prohibit production from more than one formation at a time. As such, this property possesses long-term development potential with a considerable number of up-hole recompletion opportunities. Average production during 2003 was 4,940 barrels per day of heavy oil and 1.6 million cubic feet per day of natural gas.

Carruthers The Carruthers property was obtained by Baytex in 1997 through the merger with Dorset Exploration Ltd. The property consists of two separate pools in the Cummings formation. During 2003, average production was 3,300 barrels per day of heavy oil and 0.6 million cubic feet per day of natural gas. Baytex drilled 35 gross (29.75 net) oil wells in the Carruthers area during 2003, resulting in 33 gross (27.75 net) oil wells and two dry holes for an overall drilling success rate of 94 percent. Baytex has continued to develop the southern pool since 1999, with 15 to 20 locations planned for 2004.

Marsden/Silverdale The Marsden/Silverdale area of Saskatchewan is characterized by quality oil of 13 to 18 API and production averaging 100 barrels per day per well. The lighter gravity oil allows production to be flow-lined to treating and disposal facilities thereby reducing trucking costs. Lower trucking costs, combined with characteristically low sand production, result in lower overall operating costs. Production averaged 3,400 barrels per day of oil and 1.1 million cubic feet per day of natural gas during 2003. Baytex drilled nine oil wells in the area during 2003, with 100 percent success. Baytex has approximately 12,000 net acres of undeveloped land in the Marsden/Silverdale area.

FRONTIER CONTRACT

In October 2002, Baytex announced the signing of a five-year crude oil supply agreement with Frontier Oil and Refining Company ("Frontier"). The agreement calls for Baytex to deliver 20,000 barrels per day of Lloyd Blend ("LLB") quality crude at Hardisty, Alberta through the Express Pipeline to Gurnsey, Wyoming. The blended crude is comprised of approximately 16,000 barrels of Baytex production and 4,000 barrels per day of diluent. Prices are fixed at 71 percent of WTI or a 29 percent LLB differential which represents the long-term differential average since 1986. This contract significantly reduces the volatility of Baytex's cash flow from its heavy oil operations.

CONVENTIONAL OIL AND GAS DISTRICT

The Conventional Oil and Gas District includes properties located in Alberta producing light and medium gravity crude oil, natural gas and related liquids. Production in this district averaged 11,010 barrels of oil equivalent per day for the year ended December 31, 2003, consisting of 2,273 barrels of oil and natural gas liquids per day and 52.4 million cubic feet per day of natural gas.

Excluding production from the Ferrier area, which was sold in March 2003, and production from the properties which were transferred to Crew Energy Inc. pursuant to the Plan of Arrangement, production in this district averaged 1,860 barrels per day of oil and 45.2 million cubic feet per day of natural gas, or 9,400 boe per day during 2003.

Leahurst Baytex began operations in the Leahurst area in 1993. Production in the area is primarily natural gas from the lower Mannville formations. The Trust holds approximately 28,000 net acres of undeveloped land in the area, interests in two gas plants and a 100-km gathering system. In 2003, the Trust drilled 7.8 net successful natural gas wells. The Leahurst area has year-round access, which allows Baytex to conduct continuous development activities. Baytex's average production for 2003 was 7.3 million cubic feet per day of natural gas in this area.

Red Earth/Goodfish Baytex commenced operations in this area through the merger with Dorset in 1997. Production includes light oil from the Slave Point and Granite Wash formations and natural gas from the Bluesky formation. In 2003, Baytex drilled 10.2 net wells in the area resulting in five net oil wells and five net natural gas wells. Baytex holds approximately 86,000 net acres of undeveloped land in this area. The Trust's average production in 2003 was 1,000 barrels per day of light oil and 9.8 million cubic feet per day of natural gas.

Nina/Darwin Baytex began operations in the Darwin area in 1998, targeting natural gas from the Bluesky formation. Production from Nina commenced in March 2001. The Trust holds approximately 34,000 net acres of undeveloped land in the area. Average production in this area in 2003 was 5.0 million cubic feet per day of natural gas.

Bon Accord The Bon Accord property was acquired by Baytex in 1997 through the merger with Dorset. Baytex utilizes 3-D seismic technology to identify productive zones in the Mannville, Nisku and Sparky formations. Baytex drilled eight wells in the Bon Accord area during 2003, resulting in five natural gas wells and one oil well. Average production was 8.4 million cubic feet per day of natural gas and 360 barrels per day of oil. Baytex currently has approximately 13,000 net acres of undeveloped land in this area.

Hamburg/Chinchaga Baytex constructed a natural gas processing plant in this area during 2003 with processing capacity of 8.0 million cubic feet per day. Baytex's production in the area averages approximately 5.0 million cubic feet per day, leaving approximately 3.0 million cubic feet per day of plant capacity for third-party processing which is expected to be filled by the end of the first quarter of 2004. Baytex has had success targeting natural gas in the Slave Point, Bluesky and Gillwood formations. Drilling activity in 2003 resulted in two successful natural gas wells. Net undeveloped landholdings in the area total 18,000 acres as at December 31, 2003.

LAND

Baytex continues to maintain a sizable and focused undeveloped land base, holding one of the largest undeveloped land positions of all oil and gas trusts. At December 31, 2003, Baytex's undeveloped landholdings totalled 728,818 net acres with an average working interest of approximately 86 percent.

The Trust spent approximately $10.0 million at land sales during 2003, acquiring approximately 92,500 net acres including Baytex's position in the prospective Seal area of north central Alberta.

Charter Land Services Ltd. has provided an independent evaluation of Baytex's undeveloped acreage as at December 31, 2003 and has assessed a replacement cost value to this acreage of $51.1 million, compared to 1,181,894 net acres and a value

of $76.4 million at the end of 2002. The lower acreage and value in 2003 is the result of the transfer of assets to Crew Energy and the sale of the Ferrier properties.

The table below summarizes the undeveloped acreage owned by Baytex as at December 31, 2003. The term "undeveloped acreage" means acreage on which Baytex does not have a productive well and includes exploratory acreage.

Farmout Program With the conversion from an exploration and production company to an energy income trust, Baytex is reducing its spending on high-risk exploration activities. As part of the transition process, Baytex conducted a review of its properties to identify lands suitable for disposition via farmout, swap or sale. These are lands that have the potential for hydrocarbon reserves but do not meet Baytex's new criteria for investment as an income trust. Baytex has identified over 125,000 net acres of such lands and has made them available to farmin, swap or purchase proposals by other companies operating in these areas. Since establishing this program in October 2003, Baytex has secured 16 well commitments through farmout transactions.

Undeveloped Land Summary

(acres)	2003			2002		
	Gross	Net	Average Working Interest	Gross	Net	Average Working Interest
Heavy Oil District	336,488	321,657	96%	323,577	315,596	98%
Conventional Oil and Gas District	515,406	407,161	79%	1,061,611	866,298	82%
Total	851,894	728,818	86%	1,385,188	1,181,894	85%
Value	$ 51.1 million			$ 76.4 million		

Drilling Activity

(number of wells)	2003		2002	
	Gross	Net	Gross	Net
Crude oil	173	158.9	106	99.6
Natural gas	67	61.4	51	39.9
Service	7	5.1	3	2.5
Dry and abandoned	19	18.0	26	25.9
Total	266	243.4	186	167.9
Success rate (%)	93%	93%	86%	85%
Average working interest (%)		92%		90%

OIL AND GAS RESERVES

The following tables summarize certain information with regard to Baytex's oil and gas reserves as evaluated by Sproule Associates Limited as at January 1, 2004. Additional information required under NI 51-101 will be included in the Annual Information Form to be filed for fiscal 2003.

Oil and Gas Reserves

	Light and Medium Crude Oil		Heavy Oil		Natural Gas Liquids	
Reserves Category	Gross[1] (Mbbls)	Net[2] (Mbbls)	Gross[1] (Mbbls)	Net[2] (Mbbls)	Gross[1] (Mbbls)	Net[2] (Mbbls)
Proved						
Developed producing	3,724	3,445	24,795	22,442	249	174
Developed non-producing	144	127	15,204	13,119	9	6
Undeveloped	1,293	1,141	17,726	16,324	4	3
Total proved	5,161	4,713	57,725	51,885	262	183
Probable	1,649	1,493	23,626	21,556	94	65
Total proved plus probable	6,810	6,206	81,351	73,441	356	248

	Natural Gas		Oil Equivalent[3]	
Reserves Category	Gross[1] (Mmcf)	Net[2] (Mmcf)	Gross[1] (Mboe)	Net[2] (Mboe)
Proved				
Developed producing	73,700	59,400	41,047	35,955
Developed non-producing	3,795	3,031	15,989	13,757
Undeveloped	4,080	3,169	19,703	17,996
Total proved	81,575	65,600	76,739	67,708
Probable	24,725	20,000	29,561	26,492
Total proved plus probable	106,300	85,600	106,300	94,200

Notes:

(1) "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others.

(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Reserves Life Index

	2003	Reserves Life Index (RLI) (years)	
	Production[1]	Total Proved	Proved Plus Probable
Crude oil (bbls/d)	25,700	6.7	9.4
Natural gas (mmcf/d)	55.8	4.0	5.2
Oil equivalent (boe/d)	35,000	6.0	8.3

(1) Excluding production associated with assets transferred to Crew Energy Inc. and assets disposed in the Ferrier area.

Net Present Value

	Net Present Value of Future Net Revenue As at January 1, 2004 Forecast Prices and Costs			
	Before Income Taxes Discounted at (%/year)			
	0%	5%	10%	15%
Reserves Category	($000s)	($000s)	($000s)	($000s)
Proved				
Developed producing	521,400	472,500	427,900	391,900
Developed non-producing	135,600	107,700	88,400	74,300
Undeveloped	108,000	80,900	61,000	46,100
Total proved	765,000	661,100	577,300	512,300
Probable	276,700	203,200	156,100	123,900
Total proved plus probable	1,041,700	864,300	733,400	636,200

Sproule January 1, 2004 Price Forecast

Year	WTI Cushing US$/Bbl	Edmonton Par Price C$/Bbl	Hardisty Heavy 12 API C$/Bbl	AECO C-Spot C$/Mmbtu	Inflation Rate %/Yr	Exchange Rate US$/C$
2004	29.63	37.99	23.80	6.04	1.5	0.75
2005	26.80	34.24	21.28	5.36	1.5	0.75
2006	25.76	32.87	20.80	4.80	1.5	0.75
2007	26.14	33.37	21.33	4.91	1.5	0.75
2008	26.53	33.87	21.84	4.98	1.5	0.75
2009	26.93	34.38	22.31	5.05	1.5	0.75
2010	27.34	34.90	22.80	5.14	1.5	0.75

Net Asset Value

The following net asset value calculation utilizes what is generally referred to as the "produce-out" net present value of Baytex's oil and gas reserves as evaluated by independent evaluators. It does not take into account the possibility of Baytex being able to recognize additional reserves in its existing properties beyond those included in the 2003 year-end report.

($ thousands)		
Proved plus probable reserves[1]	$	733,400
Undeveloped land[2]		51,115
Net debt[3]		(213,572)
Net asset value	$	570,943
Total trust units outstanding[4]		64,715
Net asset value per trust unit	$	8.82

Notes:

(1) As evaluated by Sproule as at January 1, 2004 discounted at 10%. Net present value of future net revenue does not represent fair market value of the reserves.

(2) As evaluated by Charter Land Services Ltd. as at December 31, 2003 on 728,818 net acres of undeveloped land.

(3) Long-term debt net of working capital as at December 31, 2003.

(4) Includes 60,821,000 trust units outstanding as at December 31, 2003 plus 3,725,000 exchangeable shares converted at an exchange ratio of 1.04530.

Reserves Reconciliation

The following table represents a reconciliation of company interest reserves by principal product type:

	Light and Medium Crude Oil			Heavy Oil		
Factors	Proved[1] (Mbbls)	Probable[1] (Mbbls)	Proved Plus Probable[1] (Mbbls)	Proved[1] (Mbbls)	Probable[1] (Mbbls)	Proved Plus Probable[1] (Mbbls)
December 31, 2002[2]	3,589	1,142	4,731	100,914	24,471	125,385
Capital additions[3]	1,931	560	2,491	8,850	4,602	13,452
Technical revisions	207	(63)	144	(43,345)	(5,447)	(48,792)
Acquisitions	80	10	90	–	–	–
Dispositions	–	–	–	–	–	–
Economic factors	–	–	–	–	–	–
Production[4]	(646)	–	(646)	(8,694)	–	(8,694)
January 1, 2004	5,161	1,649	6,810	57,725	23,626	81,351

	Natural Gas Liquids			Natural Gas		
Factors	Proved[1] (Mbbls)	Probable[1] (Mbbls)	Proved Plus Probable[1] (Mbbls)	Proved[1] (Mmcf)	Probable[1] (Mmcf)	Proved Plus Probable[1] (Mmcf)
December 31, 2002[2]	81	24	105	75,573	13,521	89,094
Capital additions[3]	69	12	81	17,925	9,249	27,174
Technical revisions	146	58	204	7,051	1,677	8,728
Acquisitions	–	–	–	1,386	278	1,664
Dispositions	–	–	–	–	–	–
Economic factors	–	–	–	–	–	–
Production[4]	(34)	–	(34)	(20,360)	–	(20,360)
January 1, 2004	262	94	356	81,575	24,725	106,300

	Oil Equivalent[5]		
Factors	Proved[1] (MBoe)	Probable[1] (MBoe)	Proved Plus Probable[1] (MBoe)
December 31, 2002[2]	117,180	27,890	145,070
Capital additions[3]	13,837	6,715	20,552
Technical revisions	(41,821)	(5,100)	(46,921)
Acquisitions	311	56	367
Dispositions	–	–	–
Economic factors	–	–	–
Production[4]	(12,768)	–	(12,768)
January 1, 2004	76,739	29,561	106,300

Notes:

(1) Reserves information as at December 31, 2002 is prepared in accordance with National Policy 2-B. Probable reserves as at December 31, 2002 represents 50% of the total probable reserves then assigned to allow more appropriate comparison with probable reserves under NI 51-101 as at January 1, 2004.

(2) As disclosed in the Information Circular dated July 25, 2003 with respect to the Plan of Arrangement resulting in the formation of Baytex Energy Trust. Reserve information based on an independent engineering evaluation of the oil and gas reserves of Baytex Energy Ltd. as at December 31, 2002 prepared by Outtrim Szabo Associates Ltd. and adjusted by Baytex after giving effect to the transfer of certain oil and gas properties to Crew Energy Inc. pursuant to the Plan of Arrangement and the sale of oil and gas assets in the Ferrier area in March 2003.

(3) Includes discoveries, extensions and improved recoveries.

(4) Production for the year ended December 31, 2003 excludes production associated with the oil and gas properties transferred to Crew Energy Inc. pursuant to the Plan of Arrangement and production associated with the oil and gas assets disposed in the Ferrier area.

(5) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

MARKETING

Crude Oil

Crude oil prices were very strong in 2003 as a number of world events impacted prices positively. Benchmark West Texas Intermediate (WTI) prices averaged US$31.04 per barrel in 2003, an increase of 19 percent from the 2002 average of US$26.08. The five-year average is US$26.49.

Prices opened the year very strongly as the prospects for an Iraqi conflict became more certain and a general strike in Venezuela held crude oil supplies off the market. During the year, reduced Iraqi supplies, Nigerian supply disruptions, increased Japanese demand resulting from nuclear plant outages and the refilling of government stockpiles all led crude oil prices to their highest annual average since the New York Mercantile Exchange (NYMEX) light sweet crude oil contract began trading in 1983.

Baytex's conventional crude oil and natural gas liquids prices reflected the strong world prices, averaging $39.04 per barrel in 2003 compared to $33.86 per barrel in 2002.

Canadian heavy oil prices generally kept pace with world oil prices in 2003. The differential between WTI and Lloyd blend prices in Alberta averaged US$8.88 per barrel in 2003 (29 percent of WTI) compared to US$6.58 per barrel in 2002 (25 percent of WTI), with the five-year average at US$7.74 (29 percent of WTI).

Baytex's heavy oil prices averaged $25.12 per barrel in 2003, compared to $26.39 in 2002. This reduction reflects the stronger Canadian dollar, the higher heavy oil differential, increased transportation costs as well as a higher mix of heavier raw crude from our Cold Lake and Ardmore properties.

2003 marked the first full year of a five-year crude oil supply agreement with Frontier Oil and Refining Company. The agreement calls for Baytex to deliver 9,000 barrels per day of blended heavy oil to Frontier in January 2003, increasing to 20,000 barrels per day in October 2003 and throughout the term of the arrangement. Prices are fixed at 71 percent of WTI, thus significantly reducing the volatility of cash flow relating to our heavy oil operations. This arrangement performed very well in 2003 as contract prices mirrored market conditions. The graph below depicts heavy oil differentials since 1994 compared to our current pricing relationship with Frontier. The graph indicates the reduced price volatility associated with the Frontier contract.

HEAVY OIL DIFFERENTIAL (US$/bbl)

Natural Gas

Natural gas prices were very strong in 2003 as abnormally cold temperatures across North America drew inventories down early in the year. U.S. gas prices, represented by the NYMEX futures contract, averaged US$5.44 per thousand cubic feet in 2003, an increase of 67 percent from US$3.25 in 2002. Daily prices for Alberta gas delivered to the AECO "C" trading hub averaged $6.64 per thousand cubic feet in 2003 compared to $4.05 in 2002. Five-year averages are US$3.85 per thousand cubic feet for the NYMEX contract and $4.93 per thousand cubic feet for Alberta daily prices.

Baytex received an average of $6.07 per thousand cubic feet for 2003 natural gas sales compared to $3.94 in 2002.

SAFETY, ENVIRONMENT AND COMMUNITY

Baytex Energy Trust has a formal policy to conduct its operations in a manner designed to protect the health and safety of its employees, contractors, and the public and to avoid an adverse impact on the environment.

In support of this policy, Baytex Energy Trust:

+ has developed and maintained health, safety and environmental management plans which include practices and procedures that comply with regulatory requirements and industry standards;
+ ensures that all employees and contract personnel understand their responsibilities through education, communication and training;
+ has developed and maintained a contractor management program to ensure contractor and subcontractor compliance with Baytex policies;
+ conducts regular review of the safety and environmental management system and conducts updates as required. Input from employees is encouraged and is considered when conducting reviews;
+ conducts regular inspections and audits on all properties operated by Baytex; and
+ has developed emergency response plans and employees have been trained to effectively respond to emergency situations.

Management is responsible for establishing health, safety and environmental policies and procedures and ensuring that all necessary resources, equipment and training is provided. In addition, corporate safety and environmental reports are presented on a quarterly basis to the Board of Directors. All employees and contractors must understand and comply with all applicable policies and procedures.

In addition to the above, Baytex participates in the Canadian Association of Petroleum Producer's Environment, Health and Safety Stewardship program. This program has been developed to set consistent safety and environmental standards throughout the Canadian oil and gas industry. The program allows industry participants to measure the quality and performance of its environment, health and safety programs against other companies. Baytex is proud to report that it has achieved a "Gold" ranking under this program for two years running.

Community

Baytex believes in enhancing the communities where employees live and work. Baytex supports causes and institutions through financial and volunteer efforts. The Trust is very proud of these associations with many not-for-profit organizations. Baytex employs 95 office staff in Calgary and 17 field staff in other areas of Alberta and Saskatchewan. Baytex encourages employees to contribute to their communities through volunteer work. Baytex regularly contributes to causes supported by its employees. Baytex also directs funding to non-profit organizations located in its key operational areas.

Baytex conducts a significant portion of its heavy oil operations on aboriginal lands. Baytex maintains a mutually beneficial business relationship with the First Nations communities on these lands and the Trust is proud of these associations.

The following discussion and analysis, dated March 5, 2004, should be read in conjunction with Baytex Energy Trust's (the "Trust") audited consolidated financial statements for the fiscal years ended December 31, 2003 and 2002. Per barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations is not a measure based on generally accepted accounting principles ("GAAP"), but is a financial term commonly used in the oil and gas industry. It represents cash generated from operating activities before changes in non-cash working capital, deferred charges and other assets and deferred credits. The Trust considers it a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments.

2003 OVERVIEW

The Trust was established on September 2, 2003 under a Plan of Arrangement involving the Trust, Baytex Energy Ltd. (the "Company") and Crew Energy Inc. ("Crew"). Under the Plan of Arrangement, the Company transferred to Crew a portion of its producing and exploratory petroleum and natural gas assets. As Crew was a related party at the effective date of the Plan of Arrangement, the assets and liabilities were transferred at book value. For each common share of the Company, shareholders received either one unit of the Trust and one-third of a common share of Crew, or one exchangeable share exchangeable initially into one trust unit and one-third of a common share of Crew. The Trust is an open-ended investment trust created pursuant to a trust indenture. The Company is a subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company, its subsidiaries and partnership. After giving effect to the Plan of

Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to Baytex Energy Ltd. The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles.

Production

The Trust's average production for fiscal 2003 decreased by six percent to 36,686 boe per day from 39,214 boe per day for fiscal 2002. This decrease was the result of property dispositions that occurred at the end of the first quarter of 2003 and the transfer of the petroleum and natural gas assets to Crew under the Plan of Arrangement effective September 2, 2003.

Light oil production decreased 28 percent to 2,273 barrels per day during 2003 from 3,154 barrels per day in 2002. Heavy oil production during 2003 was 23,911 barrels per day, consistent with production of 23,967 barrels per day during fiscal 2002. Natural gas production for 2003 decreased by 13 percent to 63.0 million cubic feet per day compared to 72.6 million cubic feet per day for the prior year.

Revenue

Petroleum and natural gas sales for 2003 decreased by four percent to $351.4 million from $365.9 million for fiscal 2002. Benchmark WTI crude oil averaged US$31.04 per barrel for 2003, representing a 19 percent increase over the US$26.08 per barrel for 2002. Correspondingly, the Trust's light oil and NGLs price increased to $39.04 per barrel from $33.86 per barrel in 2002. The heavy oil price decreased five percent to $25.12 per barrel in 2003 from $26.39 per barrel in 2002, principally due to the increase in heavy oil differentials. Natural gas prices were 54 percent higher in 2003, averaging $6.07 per thousand cubic feet compared to $3.94 per thousand cubic feet during the previous year. Overall, after accounting for financial derivative contracts, the Trust averaged $26.72 per boe for 2003, a 4 percent increase from $25.56 per boe received in the prior year. For the per-sales-unit calculations, heavy oil sales for 2003 were 650 barrels per day lower than the production for the year due to inventory in transit under the Frontier supply agreement.

For 2003, light oil revenue decreased 17 percent over 2002, as the 15 percent increase in wellhead prices was offset by a 28 percent decrease in production. Revenue from heavy oil

Production by Area

	Light Oil and NGLs (bbls/d)	Heavy Oil (bbls/d)	Natural Gas (mmcf/d)	Barrels of Oil Equivalent (boe/d)
2003				
Heavy Oil District	–	23,911	10.6	25,676
Conventional Oil and Gas District	2,273	–	52.4	11,010
Total Production	2,273	23,911	63.0	36,686
2002				
Heavy Oil District	–	23,967	10.5	25,710
Conventional Oil and Gas District	3,154	–	62.1	13,504
Total Production	3,154	23,967	72.6	39,214

decreased eight percent due to a five percent decrease in wellhead prices and a three percent decrease in sales volumes. Natural gas revenue increased 34 percent as the 13 percent production decrease was offset by a 54 percent increase in wellhead prices.

Royalties

For the year ended December 31, 2003, royalties increased 14 percent to $67.2 million from $58.9 million last year and were 17.4 percent of sales compared to 15.7 percent of sales in 2002. Higher realized gas prices resulted in higher royalty rates. Royalties for 2003 were 17.8 percent of sales for light oil, 13.8 percent for heavy oil and 22.9 percent for natural gas. These rates compared to 16.7 percent, 13.9 percent and 19.5 percent, respectively, for 2002.

Operating Expenses

Operating expenses for 2003 increased 14 percent to $86.0 million from $75.2 million for 2002. This increase is attributable to the disposition of properties with lower operating costs and a general increase in field operating costs. Operating expenses were $6.54 per boe for 2003 compared to $5.26 per boe for the prior year. Operating expenses were $8.32 per barrel of light oil, $7.34 per barrel of heavy oil and $0.73 per thousand cubic feet of natural gas for 2003 versus $5.83, $5.99 and $0.61, respectively, for 2002.

Gross Revenue Analysis

	2003		2002	
	$ thousands	$/Unit(1)	$ thousands	$/Unit(1)
Light oil	32,393	39.04	38,985	33.86
Heavy oil	213,297	25.12	230,874	26.39
Derivative contract loss	(33,777)	(3.62)	(10,622)	(1.07)
Total oil revenue	211,913	22.74	259,237	26.19
Natural gas revenue	139,491	6.07	104,284	3.94
Derivative contract gain	–	–	2,339	0.09
Total natural gas revenue	139,491	6.07	106,623	4.03
Total revenue (boe @ 6:1)	351,404	26.72	365,860	25.56

(1) Per-unit oil revenue is in $/bbl; per unit natural gas revenue is in $/mcf.

Operating Netback

	Light Oil & NGLs ($/bbl)		Heavy Oil ($/bbl)		Total Oil & NGLs ($/bbl)		Natural Gas ($/mcf)		BOE ($/boe)	
	2003	2002	2003	2002	2003	2002	2003	2002	2003	2002
Sales price	39.04	33.86	25.12	26.39	26.36	27.26	6.07	3.94	29.28	26.14
Royalties	(6.96)	(5.67)	(3.47)	(3.66)	(3.78)	(3.89)	(1.39)	(0.77)	(5.11)	(4.12)
Operating costs	(8.32)	(5.83)	(7.34)	(5.99)	(7.43)	(5.97)	(0.73)	(0.61)	(6.54)	(5.26)
Operating netback	23.76	22.36	14.31	16.74	15.15	17.40	3.95	2.56	17.63	16.76

Note: Sales prices in this table are before the loss/gain recognized on financial derivative contracts.

General and Administrative Expenses

General and administrative expenses for 2003 were $8.9 million, compared to $6.7 million a year ago. On a sales-unit basis, these expenses increased to $0.67 per boe from $0.47 per boe. In accordance with the full-cost accounting policy, $4.4 million of expenses were capitalized in 2003, compared with $6.7 million capitalized in 2002. The amount of capitalized expenses has been reduced due to lower exploration activity since the effective date of the Plan of Arrangement.

Unit-based Compensation

The Trust accounts for compensation expense based on the fair value of rights granted under its unit-based compensation plan. As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the consolidated financial statements for unexercised rights. Compensation expense of $0.22 million was recorded as compensation expense for all trust unit rights granted on or after January 1, 2003.

Compensation expense was also calculated on the stock options outstanding prior to the Plan of Arrangement. Compensation expense of $0.52 million was recorded as compensation expense for all stock options granted on or after January 1, 2003. All outstanding stock options were cancelled or exercised effective September 2, 2003.

Interest Expense

For 2003, interest expenses on long-term debt were $23.5 million compared to $25.2 million for 2002. The decrease is due to the redemption of the senior secured notes and the impact of the stronger Canadian dollar on U.S. dollar based interest expenses.

Costs on Redemption and Exchange of Notes

On July 9, 2003, the Company completed an exchange offer related to its previously outstanding US$150 million 10.5 percent senior subordinated notes due 2011 (the "Old Notes"). The Company issued US$179.7 million of 9.625 percent senior subordinated notes due 2010 in exchange for US$149.8 million of the Old Notes and incurred a non-cash loss of $40.0 million on the completion of this transaction, which was recognized in income. Also recognized in income is $4.7 million of costs on the redemption of the US$57 million senior 7.23 percent secured notes.

Depletion and Depreciation

Depletion and depreciation increased to $116.3 million for 2003 compared to $106.8 million last year. On a sales-unit basis, the provision for 2003 was $8.69 per boe compared to $7.46 per boe for 2002 due to the revisions in proved reserves under the new standards of disclosure for oil and gas activities, National Instrument 51-101 ("NI 51-101"), as mandated by the Canadian Securities Administrators for year-ends beginning with December 31, 2003.

General and Administrative Expenses

($ thousands)

	2003	2002
Gross corporate expense	$ 20,496	$ 19,328
Operator's recoveries	(7,166)	(5,842)
Subtotal	13,330	13,486
Full-cost accounting capitalization	(4,403)	(6,743)
Net expense	$ 8,927	$ 6,743

The ceiling test was calculated at December 31, 2003 using the proved reserves as determined under NI 51-101 and at prices at year-end. No write-down was required at December 31, 2003 under this calculation.

Site Restoration Costs

Site restoration costs for the year ended December 31, 2003 increased to $2.9 million from $2.8 million last year. On a sales-unit basis, the provision for 2003 was $0.22 per boe compared to $0.20 per boe for 2002 due to the changes in the proved reserves used in the calculation.

Foreign Exchange

Foreign exchange gain for 2003 was $52.1 million compared to $2.7 million in 2002. The 2003 gain is based on the translation of the Company's U.S. dollar denominated long-term debt at 0.7737 at December 31, 2003 compared to 0.6331 at December 31, 2002. The 2002 gain is based on translation at 0.6331 at December 31, 2002 compared to 0.6279 at December 31, 2001.

Income Taxes

Current tax expenses were $9.7 million for 2003 compared to $9.7 million last year. The 2003 current tax expense is comprised of $8.0 million of Saskatchewan Capital Tax and $1.7 million of Large Corporation Tax compared to $8.1 million and $1.6 million, respectively, in 2002.

The fiscal 2003 provision for future income taxes was a recovery of $13.6 million compared to $37.9 million for the prior year. The future income tax recovery for 2003 included a non-recurring adjustment resulting from a 0.5 percent decrease to the Alberta corporate income tax rate and from the federal legislation introduced to change the taxation of resource income. The federal resource tax changes include a change in the federal income tax rate, deductibility of crown royalties and elimination of the resource allowance, to be phased in over the next five years. These changes are considered substantially enacted for the purposes of GAAP and the Company's future income tax liability has been reduced accordingly.

Canadian Tax Pools

($ thousands)	December 31, 2003
Cumulative Canadian exploration expense	9,000
Cumulative Canadian development expense	63,000
Cumulative Canadian oil and gas property expense	96,000
Undepreciated capital cost	148,000
Other	48,000
Total tax pools	364,000

Cash Flow from Operations

Cash flow from operations for the year ended December 31, 2003 decreased 28 percent to $138.2 million from $191.1 million for the previous year due to higher costs related to derivative contracts and reorganization under the Plan of Arrangement. On a barrel of oil equivalent basis, cash flow from operations was $10.51 for 2003 compared to $13.35 for 2002.

Capital Expenditures

Exploration and development expenditures increased to $180.1 million for 2003 compared to $136.3 million last year. Total capital expenditures for the last two years are summarized in the table below.

Liquidity and Capital Resources

At December 31, 2003, total net debt (including working capital) was $213.6 million compared to $362.8 million at December 31, 2002. The decrease in total debt at year-end 2003 compared to 2002 was the result of proceeds from assets sales at the end of March 2003, and an equity issue of 6.5 million trust units for net proceeds of $61.5 million in December 2003.

The Company's debt structure consists of two components. The first component is the senior credit facilities. On September 3, 2003, the Company entered into a new credit agreement with a syndicate of chartered banks. The credit

Cash Flow

	2003		2002	
	$/boe	Percent	$/boe	Percent
Production revenue	29.28	100	26.14	100
Derivative contract loss	(2.57)	(9)	(0.57)	(2)
Royalties	(5.11)	(17)	(4.12)	(16)
Operating expenses	(6.54)	(22)	(5.26)	(20)
Operating netback	15.06	52	16.19	62
General and administrative expenses	(0.68)	(2)	(0.47)	(2)
Reorganization costs	(1.43)	(5)	–	–
Interest expense	(1.71)	(6)	(1.69)	(6)
Current income taxes	(0.73)	(3)	(0.68)	(3)
Cash flow	10.51	36	13.35	51

Capital Expenditures

($ thousands)	2003	2002
Land	$ 14,138	$ 13,834
Seismic	5,436	8,183
Drilling and completion	111,772	81,862
Equipment	42,365	24,507
Other	6,401	7,949
Total exploration and development	180,112	136,335
Property acquisitions	6,644	45,713
Property dispositions	(137,493)	(55,580)
Net capital expenditures	$ 49,263	$ 126,468

facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The facilities aggregating $165 million are subject to semi-annual reviews beginning in November 2003 and are secured by a floating charge over all of the Company's assets. At December 31, 2003, there were no amounts outstanding under the bank credit facilities.

The second component is the senior subordinated notes. On February 12, 2001, the Company issued US$150 million of senior subordinated notes ("Old Notes") bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities. On July 9, 2003, the Company completed an exchange offer related to its Old Notes. The Company issued US$179.7 million ($247.1 million) of 9.625 percent senior subordinated notes due July 15, 2010 ("New Notes") in exchange for US$149.8 million of the Old Notes and incurred a non-cash loss of $40.0 million on the completion of this transaction, which was recognized in income. The New Notes are unsecured and are subordinate to the Company's bank credit facilities.

The Trust believes that cash flow generated from its operations, together with existing capacity under the bank credit facilities, will be sufficient to finance current operations and planned capital expenditures for the next year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments.

Unitholders' Equity

The Trust is authorized to issue an unlimited number of trust units. Pursuant to the Plan of Arrangement, 53.3 million trust units and 4.7 million exchangeable shares were issued on September 2, 2003 on the exchange of the common shares of the Company. An additional 6.5 million trust units were issued on December 12, 2003 for gross proceeds of $65 million.

At December 31, 2003, there were 3.7 million exchangeable shares outstanding. The exchange ratio of these shares was 1.04530 trust units per exchangeable share at year-end. During 2003, a total of 1.0 million exchangeable shares were exchanged for trust units.

Cash Distributions

Total cash distributions of $0.60 per unit were declared from September to December 2003. During the first quarter of 2004, the monthly cash distribution of $0.15 per unit is estimated to be within the Trust's target distribution range of between 60 percent and 70 percent of cash flow.

Off-Balance Sheet Arrangements and Contractual Obligations

The Trust uses various financial derivative instruments, the fair values of which are not reflected on the consolidated balance sheet, to reduce exposure to commodity and currency fluctuations. These risks, and the Trust's risk management policy, are discussed in "Risk and Risk Management." The Trust's current position with respect to its financial derivative contracts is detailed in note 15 of the consolidated financial statements.

The Trust has ongoing obligations related to abandonment and reclamation of well and facility sites which have reached the end of their economic lives. Programs to abandon and reclaim well and facility sites are undertaken regularly in accordance with applicable legislative requirements.

The Trust has assumed various contractual obligations and commitments, as detailed in the table below, in the normal course of operations and financing activities. These obligations and commitments have been considered when assessing the cash requirements in the above discussion of future liquidity.

Risk and Risk Management

The exploration for and the development, production and marketing of petroleum and natural gas involves a wide range of business and financial risks, some of which are beyond the Trust's control. Included in these risks are the uncertainty of finding new reserves, the fluctuations of commodity prices, the volatile nature of interest and foreign exchange rates, and the possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and the Trust competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing the Trust are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure a balance between risk and reward. The Trust's ability to increase its production, revenue and cash flow depends on its success not only in developing its existing properties, but also in acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practice analysis being conducted on all projects, there are numerous uncertainties inherent in estimating quantities of petroleum and natural gas reserves, including future oil and natural gas prices, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating petroleum and natural

Contractual Obligations

($ thousands)

		Payments Due by Period			
	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Long-term debt[1]	232,562	–	–	–	232,562
Operating leases	1,660	1,328	332	–	–
Transportation agreements	7,295	3,192	3,299	804	–
Total contractual obligations	241,517	4,520	3,631	804	232,562

(1) Total US $179.9 million

gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. An independent engineering firm evaluates the Trust's properties annually to determine a fair estimate of reserves. The Reserves Evaluation Committee, consisting of qualified members of the Company's Board, of the Board of Directors assists the Board in their annual review of the reserve estimates.

The provision for depletion and depreciation in the financial statements and the ceiling test are based on proved reserve estimates. Any future significant reserve revisions could result in a full-cost accounting write-down or material changes to the annual rate of depletion and depreciation.

The financial risks that the Trust is exposed to as part of the normal course of its business can be managed with various financial derivative instruments, in addition to fixed-price physical delivery contracts. The use of derivative instruments is governed under formal internal policies and subject to limits established by the Board of Directors. Derivative instruments are not used for speculative or trading purposes.

The Trust's financial results can be significantly affected by the prices received for petroleum and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, the Trust has a risk management program that may be used to protect the prices of oil and natural gas on a portion of the total expected production. The objective is to decrease exposure to market volatility and ensure the Trust's ability to finance its distributions and capital program. The Trust recognizes gains or losses on financial derivative contracts as oil and natural gas production revenue when the associated production occurs.

The Trust's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices generally denominated in U.S. dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the U.S. dollar denominated long-term debt. The related foreign exchange gains and losses are included in net income. There is no plan at this time to fix the exchange rate on any of the Trust's long-term borrowings.

The Trust is exposed to changes in interest rates as the Company's banking facilities are based on the lenders' prime lending rate and short-term Bankers' Acceptance rates.

The Trust's current position with respect to its financial derivative contracts is detailed in note 15 of the consolidated financial statements.

CRITICAL ACCOUNTING POLICIES

The preparation of the consolidated financial statements in accordance with generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. These critical estimates are discussed below.

Oil And Gas Accounting

The Trust follows the full-cost accounting guideline to account for its petroleum and natural gas operations. Under this method, all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre. These capitalized costs, along with estimated future development costs, are depleted and depreciated on a unit-of-production basis using estimated proved petroleum and natural gas reserves. Unit-of-production calculations are also used in the determination of the site restoration expense. By their inclusion in the unit-of-production calculation, reserve

estimates are a significant component of the calculation of depletion and depreciation and site restoration expense.

Independent engineers engaged by the Trust use all available geological, reservoir, and production performance data to prepare the reserve estimates. These estimates are reviewed and revised, either upward or downward, as new information becomes available. Revisions are necessary due to changes in assumptions based on reservoir performance, prices, economic conditions, government restrictions and other relevant factors. If reserve estimates are revised downward, net income could be affected by increased depletion and depreciation and site restoration expense.

Impairment of Petroleum and Natural Gas Assets

Companies that use the full-cost method of accounting for oil and natural gas operations are required to perform a ceiling test each quarter that calculates a limit for the net carrying cost of petroleum and natural gas assets. The ceiling test calculation utilizes and holds constant the prices and costs in effect at the end of the period. An estimate is made of the ultimate recoverable amount from future net revenue using proved reserves and period end prices, plus the net costs of major development projects and unproved properties, less future removal and site restoration costs, overhead, financing costs and income taxes. The calculation of future net revenue in the ceiling test can be significantly impacted by fluctuations in any of these estimates. An impairment loss is recognized if the amount calculated under the ceiling test is less than the carrying costs of the Trust's petroleum and natural gas assets and can result in a significant accounting loss for a particular period.

New Accounting Pronouncements

In November 2002, the Canadian Institute of Chartered Accountants ("CICA") amended its accounting guideline on hedging relationships, which was originally issued in November 2001. The guideline addresses the identification, designation, documentation and effectiveness of hedging transactions for the purposes of applying hedge accounting. It also establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective to continue accrual accounting for positions hedged with derivatives. The new guideline is effective for fiscal years beginning on or after July 1, 2003. The Trust is evaluating the impact that the adoption of AcG-13 will have on its results of operations.

The Trust has elected to prospectively adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments," pursuant to the transitional provisions contained therein. Under this amended standard, the Trust is required to account for compensation expense based on the fair value of rights granted under its unit-based compensation plan. As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the financial statements for unexercised rights. Compensation expense of \$0.22 million was recorded as compensation expense for all trust unit rights granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus.

The adoption of these amendments also impacted the stock options outstanding prior to the Plan of Arrangement. Compensation expense of \$0.52 million was recorded for all stock options granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus. For stock options granted prior to January 1, 2003, the pro forma

earnings impact of related stock-based compensation expense is disclosed in note 10 of the consolidated financial statements.

In March 2003, the CICA issued Section 3110, "Asset Retirement Obligations." This section requires recognition of a liability at discounted fair value for the future abandonment and reclamation associated with the petroleum and natural gas properties. The fair value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The new standard is effective for all fiscal years beginning on or after January 1, 2004. The impact of adoption of this standard is estimated to be an increase in asset retirement obligation on the balance sheet of $33 million at December 31, 2003.

In February 2003, the CICA issued Accounting Guideline 14, "Disclosure of Guarantees" ("AcG-14"). AcG-14 establishes the disclosures required for obligations under certain guarantees. The disclosure requirements are effective for interim and annual periods beginning on or after January 1, 2003 and have been made in note 16 of the consolidated financial statements.

In 2003, the CICA issued Accounting Guideline 16, "Oil and Gas Accounting – Full-Cost" ("AcG-16"). The guideline is effective for fiscal years beginning on or after January 1, 2004. The new guideline proposes amendments to the ceiling test calculation applied by the Trust. The ceiling test was changed to a two-stage process which is to be performed at least annually. The first stage of the test is a recognition test which compares the undiscounted future cash flow from proved reserves to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the carrying amount of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves. The adoption of this new guideline on January 1, 2004 is not anticipated to have an impact on the financial results of the Trust.

On November 10, 2003, the CICA issued a draft EIC (D37) on "Income Trusts - Exchangeable Units." The EIC proposes that the retained interest of the exchangeable shareholders should be presented on the balance sheet as a non-controlling interest separate and distinct from unitholder's equity. This draft EIC is currently under review and was not enacted in final form as of the time of release of the Trust's 2003 consolidated financial statements.

In June 2003, the CICA issued Accounting Guideline 15, "Consolidation of Variable Interest Entities," which deals with the consolidation of entities that are subject to control on a basis other than ownership of voting interests. This guideline is effective for annual and interim periods beginning on or after November 1, 2004. The Trust has assessed that this new guideline is not applicable based on the current structure of the Trust and therefore will have no impact on the consolidated financial statements of the Trust.

FOURTH QUARTER 2003

The following discussion reviews the Trust's results of operations for the fourth quarter of 2003.

Total production for the fourth quarter of 2003 decreased nine percent to 36,195 boe per day from 39,890 boe per day for the same period in 2002, due to the sale of properties in March 2003 in the Ferrier area and the transfer of properties

to Crew in September 2003. Petroleum and natural gas sales decreased 23 percent to $77.9 million for the fourth quarter of 2003 from $100.6 million for the fourth quarter of 2002. Total royalties decreased 19 percent to $13.5 million for the fourth quarter of 2003 from $16.7 million for the same period in 2002. Operating expenses for the fourth quarter of 2003 increased 11 percent to $22.1 million from $19.8 million for the corresponding quarter in 2002. Operating expenses were $6.74 per boe for the fourth quarter of 2003 compared to $5.40 per boe for the fourth quarter of 2002.

General and administrative expenses for the fourth quarter of 2003 were $3.6 million compared to $1.6 million in 2002. On a per-sales-unit basis, these expenses were $1.07 per boe compared to $0.44 per boe as no expenses were capitalized in the fourth quarter of 2003 due to lower exploration activity since the effective date of the Plan of Arrangement.

Interest expenses on long-term notes and bank debt were $5.2 million for the fourth quarter of 2003, down from $7.2 million in the same quarter of 2002.The decrease is due to the redemption of the senior secured notes and the impact of the stronger Canadian dollar on U.S. dollar based interest expenses.

The foreign exchange gain in the fourth quarter of 2003 was $10.4 million compared to a gain of $1.3 million in the same period in 2002.

The provision for depletion and depreciation increased to $40.4 million for the fourth quarter of 2003 compared to $27.1 million for the same quarter of 2002. On a per-sales-unit basis, the provision for the current quarter was $12.14 per boe compared to $7.39 per boe for the same quarter in 2002, due to the revision in proved reserves under the new standards of disclosure for oil and gas activities, NI 51-101, as mandated by the Canadian Securities Administrators for year-ends beginning with December 31, 2003.

Net income for the fourth quarter of 2003 was $8.9 million compared to $12.8 million for the corresponding quarter of 2002. In 2003, increased depletion expense was offset by foreign exchange gains and a recovery of future income taxes.

Outstanding Unit Information

At of February 29, 2004, the Trust had 61,027,681 units and 3,530,506 exchangeable shares outstanding. The exchange ratio at February 29, 2004 was 1.07444 trust units per exchangeable share.

Selected Annual Financial Information

($ thousands, except per-unit amounts)	2003	2002	2001
Revenue	$ 351,404	$ 365,860	$ 329,700
Net income (loss)	38,138	45,136	(137,107)
Per-unit basic	0.69	0.86	(2.77)
Per-unit diluted	0.67	0.85	(2.77)
Total assets	959,136	997,760	967,046
Total long-term financial liabilities	232,562	326,977	330,102
Cash distributions declared(1)	$ 0.60	$ –	$ –

(1) Total unit distributions declared since September 2, 2003.

Overall production for 2003 was 36,686 boe per day which represented a six percent decrease from 39,214 boe per day in 2002. Average wellhead prices received during 2003 were $29.28 per boe compared to $26.14 during 2002. Production in 2001 was 43,488 boe per day. Average wellhead prices received in 2001 were $21.37 per boe. Total revenue for 2003 was $351.4 million compared to $365.9 million in 2002 and $329.7 million in 2001.

Due to wide heavy oil differentials at year-end 2001, the Trust incurred a $131.3 million ceiling test write-down (net of $103.2 million of future income taxes). This amount was recognized as additional depletion and depreciation for the year ended December 31, 2001.

The decrease in total debt at year-end 2003 compared to 2002 was the result of proceeds from asset sales at the end of March 2003 and an equity issue of 6.5 million trust units for net proceeds of $61.5 million in December 2003.

Quarterly Financial Information (unaudited)

				2003				2002
($ thousands, except per-unit amounts)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Revenue	77,869	87,200	79,288	107,047	100,590	94,633	91,507	79,130
Cash flow from operations	30,179	19,975	33,372	54,707	53,116	48,637	49,208	40,125
Per unit basic	0.51	0.36	0.62	1.03	0.69	0.93	0.95	0.77
Per unit diluted	0.51	0.36	0.61	1.01	0.67	0.91	0.93	0.76
Net income (loss)	8,881	(45,516)	41,830	32,943	12,791	3,687	21,354	7,304
Per unit basic	0.15	(0.83)	0.78	0.62	0.24	0.07	0.41	0.14
Per unit diluted	0.15	(0.83)	0.76	0.61	0.24	0.07	0.40	0.14
Production								
Light oil and NGLs (bbls/d)	1,982	1,989	2,167	2,969	2,909	2,999	2,904	3,818
Heavy oil (bbls/d)	24,400	25,123	22,816	23,278	25,009	23,504	24,498	22,838
Total oil and NGLs (bbls/d)	26,382	27,112	24,983	26,247	27,918	26,503	27,402	26,656
Natural gas (mmcf/d)	58.9	61.8	57.5	74.0	71.8	71.3	73.3	73.7
Barrels of oil equivalent (boe/d @ 6:1)	36,195	37,412	34,574	38,580	39,890	38,391	39,625	38,948
Average Prices								
WTI oil (US$/bbl)	31.18	20.20	28.91	33.86	28.15	28.27	26.25	21.64
Edmonton par oil ($/bbl)	39.56	40.94	41.08	50.91	42.81	44.02	40.40	33.51
BTE light oil ($/bbl)	36.41	34.43	37.13	45.41	37.67	37.36	34.53	27.58
BTE heavy oil ($/bbl)	22.40	24.19	22.98	31.48	26.09	31.03	26.64	21.58
BTE total oil ($/bbl)	23.48	24.92	24.24	33.15	37.30	31.75	27.47	22.44
BTE natural gas ($/mcf)	5.37	5.62	6.05	7.02	5.29	3.33	3.94	3.19
BTE oil equivalent ($/boe)	25.90	27.36	27.63	36.14	28.64	28.10	26.29	21.39

Management, in accordance with Canadian generally accepted accounting principles, has prepared the accompanying consolidated financial statements of Baytex Energy Trust. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

Deloitte & Touche LLP were appointed by the Trust's unitholders to express an opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the independent auditors to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit Committee without the presence of management.

Raymond T. Chan, CA
President and Chief Executive Officer
Baytex Energy Ltd.
March 5, 2004

Daniel G. Belot
Vice President, Finance and Chief Financial Officer
Baytex Energy Ltd.

To the Unitholders of Baytex Energy Trust

We have audited the consolidated balance sheets of Baytex Energy Trust (the "Trust") as at December 31, 2003 and 2002 and the consolidated statements of operations and accumulated income (deficit) and of cash flows for the years then ended. These consolidated financial statements are the responsibility of the management of the Trust. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

On March 5, 2004, we reported separately to the Trustee and Unitholders of Baytex Energy Trust on the consolidated financial statements for the same period, prepared in accordance with Canadian generally accepted accounting principles but which included Note 17, United States Accounting Principles and Reporting.

Deloitte + Touche LLP

Chartered Accountants

Calgary, Alberta
March 5, 2004

CONSOLIDATED BALANCE SHEETS

As at December 31 *(thousands)*	2003	2002
Assets		
Current assets		
Cash and short-term investments	$ 53,731	$ 4,098
Accounts receivable	48,608	52,667
Crude oil inventory	5,900	–
	108,239	56,765
Deferred charges and other assets	7,764	8,679
Petroleum and natural gas properties *(note 5)*	843,133	932,316
	$ 959,136	$ 997,760
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 80,126	$ 92,563
Distributions payable to unitholders	9,123	–
	89,249	92,563
Long-term debt *(note 7)*	232,562	326,977
Deferred credits *(note 8)*	–	12,181
Provision for future site restoration costs	23,483	21,950
Future income taxes *(note 12)*	174,385	184,402
	519,679	638,073
Commitments and contingencies *(note 16)*		
Unitholders' Equity		
Unitholders' capital *(note 9)*	446,594	398,176
Exchangeable shares *(note 9)*	26,372	–
Contributed surplus *(note 10)*	224	–
Accumulated distributions	(33,382)	–
Accumulated deficit	(351)	(38,489)
	439,457	359,687
	$ 959,136	$ 997,760

See accompanying notes to the consolidated financial statements.

On behalf of the Board

Naveen Dargan
Director
Baytex Energy Ltd.

W. A. Blake Cassidy
Director
Baytex Energy Ltd.

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED DEFICIT

Years Ended December 31 *(thousands, except per-unit data)*	2003	2002
Revenue		
Petroleum and natural gas sales	$ 351,404	$ 365,860
Royalties	(67,175)	(58,922)
	284,229	306,938
Expenses		
Operating	86,034	75,228
General and administrative	8,927	6,743
Unit-based compensation *(note 10)*	739	–
Interest *(note 7)*	23,548	25,217
Costs on redemption and exchange of notes *(note 7)*	44,771	–
Foreign exchange gain *(note 7)*	(52,101)	(2,691)
Depletion and depreciation	116,317	106,834
Site restoration costs	2,973	2,799
Reorganization costs *(note 4)*	18,851	–
	250,059	214,130
Income before income taxes	34,170	92,808
Income taxes (recovery) *(note 12)*		
Current	9,663	9,716
Future	(13,631)	37,956
	(3,968)	47,672
Net income	38,138	45,136
Deficit, beginning of year, as previously reported	(38,489)	(75,954)
Accounting policy change for foreign exchange *(note 3)*	–	(7,671)
Deficit, beginning of year, as restated	(38,489)	(83,625)
Accumulated deficit, end of year	$ (351)	$ (38,489)
Net income per trust unit *(note 11)*		
Basic	$ 0.69	$ 0.86
Diluted	$ 0.67	$ 0.85

See accompanying notes to the consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(thousands)*	2003	2002
Cash provided by (used in):		
Operating activities		
Net income	$ 38,138	$ 45,136
Items not affecting cash:		
Unit-based compensation *(note 10)*	739	–
Amortization of deferred charges	1,027	1,052
Costs on redemption and exchange of notes *(note 7)*	44,771	–
Foreign exchange gain	(52,101)	(2,691)
Depletion and depreciation	116,317	106,834
Site restoration costs	2,973	2,799
Future income taxes (recovery)	(13,631)	37,956
Cash flow from operations	138,233	191,086
Change in non-cash working capital *(note 13)*	(8,060)	1,272
(Increase) decrease in deferred charges and other assets	211	(1,057)
Decrease in deferred credits	(2,213)	(18,694)
	128,171	172,607
Financing activities		
Redemption of senior secured notes *(note 7)*	(89,950)	–
Decrease in bank loan and other debt	–	(76,254)
Increase in deferred charges and other assets	(7,425)	–
Increase in deferred credits	–	12,181
Issue of trust units *(note 9)*	61,525	–
Payments of distributions	(24,259)	–
Issue of common shares *(note 9)*	37,049	3,497
Repurchase of common shares	–	(55)
	(23,060)	(60,631)
Investing activities		
Petroleum and natural gas property expenditures	(186,756)	(182,048)
Disposal of petroleum and natural gas properties	137,493	55,580
Properties held for sale	–	(46,895)
Change in non-cash working capital *(note 13)*	(6,215)	65,485
	(55,478)	(107,878)
Change in cash and short-term investments during the year	49,633	4,098
Cash and short-term investments, beginning of year	4,098	–
Cash and short-term investments, end of year	$ 53,731	$ 4,098

See accompanying notes to the consolidated financial statements.

1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement involving the Trust, Baytex Energy Ltd. (the "Company") and Crew Energy Inc. ("Crew"). Under the Plan of Arrangement, the Company transferred to Crew a portion of the producing and exploratory oil and natural gas assets. For each common share of the Company, shareholders received either one unit of the Trust and one-third of a common share of Crew, or one exchangeable share exchangeable initially into one trust unit and one-third of a common share of Crew. The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, the Company is a wholly owned subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company and its subsidiaries and partnership. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to the Company. The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles as described in note 2.

2. SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries from the respective dates of acquisition of the subsidiary companies. Inter-company transactions and balances are eliminated upon consolidation.

Measurement Uncertainty

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenues and expenses during the reporting period. Actual results can differ from those estimates.

In particular, amounts recorded for depreciation and depletion and amounts used for ceiling test calculations are based on estimates of petroleum and natural gas reserves and future costs required to develop those reserves. The Trust's reserve estimates are evaluated annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

Cash and Short-term Investments

Cash and short-term investments include monies on deposit and short-term investments, accounted for at cost, which have an initial maturity date of not more that 90 days.

Crude Oil Inventory

Crude oil inventory, consisting of production in transit in pipelines at the balance sheet date pursuant to a long-term crude oil supply agreement, is valued at the lower of cost or net realizable value.

Petroleum and Natural Gas Operations

The Trust follows the full-cost method of accounting for its petroleum and natural gas operations whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre and charged against income, as set out below. Such costs include land acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities and do not include any costs related to production or general overhead expenses. These costs along with estimated future capital costs that are based on current costs and that are incurred in developing proved reserves are depleted and depreciated on a unit-of-production basis using estimated gross proved petroleum and natural gas reserves. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs. Unproved properties are evaluated for impairment on an annual basis.

Gains or losses on the disposition of petroleum and natural gas properties are recognized only when crediting the proceeds to costs would result in a change of 20 percent or more in the depletion rate.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). Under this test, an estimate is made of the ultimate recoverable amount from future net revenues using proved reserves plus the net costs of major development projects and unproved properties, less future removal and site restoration costs, overhead, financing costs and income taxes, using period end prices and costs. If the net carrying costs exceed the ultimate recoverable amount, additional depletion and depreciation is provided.

Provision for Future Site Restoration Costs

Estimates are made of the future site restoration costs relating to the Trust's petroleum and natural gas properties at the end of their economic life, based on year-end values, in accordance with current legislative requirements and industry practice. Annual charges are provided on a unit-of-production method. Actual expenditures incurred are applied against the provision for future site restoration costs.

Joint Interests

A portion of the Trust's exploration, development and production activities is conducted jointly with others. These consolidated financial statements reflect only the Trust's proportionate interest in such activities.

Foreign Currency Translation

Foreign currency denominated monetary items are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recognized in income.

Revenue and expenses are translated at the monthly average rate of exchange. Translation gains and losses are included in net income.

Deferred Charges and Other Assets

Financing costs related to the exchange of the senior subordinated notes have been deferred and are amortized over the term of the notes on a straight-line basis.

Financial Instruments

The Trust formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policies included the permitted use of derivative financial instruments, including swaps and collars, used to manage these fluctuations. All transactions of this nature entered into by the Trust are related to an underlying financial instrument or to future petroleum and natural gas production. The Trust does not use derivative financial instruments for trading or speculative purposes. Gains and losses on derivative contracts are recognized in income based on the underlying financial instrument or the future petroleum and natural gas production in the same period that the transactions are settled. The fair values of derivative instruments are not recorded in the consolidated balance sheet.

Gains and losses related to derivative financial instruments that have been closed prior to the end of the term are deferred and recognized in the consolidated statement of operations over the original term of the instrument.

Future Income Taxes

The Trust is a unit trust for income tax purposes, and is taxable on taxable income not allocated to the unitholders. From inception on September 2, 2003, the Trust has allocated all of its taxable income to the unitholders, and accordingly, no provision for income taxes is required at the Trust level.

The Company is subject to corporate income taxes and follows the liability method of accounting for income taxes. Income taxes are accounted for under the liability method of tax allocation, which determines future income taxes based on the differences between assets and liabilities reported for financial accounting purposes and those reported for tax purposes. Future income taxes are calculated using tax rates anticipated to apply in periods that temporary differences are expected to reverse.

Flow-through Shares

The Company had financed a portion of its exploration and development activities through the issue of flow-through shares. Under the terms of the flow-through share agreements, the tax attributes of the related expenditure are renounced to the subscribers. Accordingly, the carrying value of the expenditures incurred and the shares issued are recorded net of tax benefits renounced to the subscribers. The Company records the gross carrying value of the expenditures and records a future tax liability for the tax benefits renounced to subscribers.

Unit-based Compensation

The Trust Unit Rights Incentive Plan is described in note 10. The exercise price of the rights granted under the plan may be reduced in future periods in accordance with the terms of the plan. Therefore, it is not possible to determine a fair value for the rights granted under the plan using a traditional option pricing model and compensation expense has been determined based on the intrinsic value of the rights at the date of exercise or at the date of the consolidated financial statements for unexercised rights.

Compensation expense associated with rights granted under the plan is recognized in earnings over the vesting period of the plan with a corresponding increase or decrease in contributed surplus. Changes in the intrinsic value of unexercised rights after the vesting period are recognized in income in the period of change with a corresponding increase or decrease in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

This method of determining compensation expense may result in large fluctuations, even recoveries, in compensation expense due to changes in the underlying trust unit price. Recoveries of compensation expense will only be recognized to the extent of previously recorded cumulative compensation expense associated with rights outstanding at the date of the financial statements.

Per-unit Amounts

Basic net income per unit is computed by dividing net income by the weighted average number of trust units, including exchangeable shares, outstanding during the year. Diluted per-unit amounts reflect the potential dilution that could occur if trust unit rights were exercised. The treasury stock method is used to determine the dilutive effect of trust unit rights, whereby any proceeds from the exercise of trust unit rights or other dilutive instruments are assumed to be used to purchase trust units at the average market price during the period.

3. CHANGES IN ACCOUNTING POLICIES

Unit-based Compensation Plan

The Trust has elected to prospectively adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" pursuant to the transitional provisions contained therein. Under this amended standard, the Trust must account for compensation expense based on the fair value of rights granted under its unit-based compensation plan. As the Trust is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the exercise date or at the date of the consolidated financial statements for unexercised rights. Compensation expense of $0.22 million was recorded as non cash general and administrative expense for all trust unit rights granted during 2003, with a corresponding amount recorded as contributed surplus.

The adoption of these amendments also impacted the stock options outstanding prior to the Plan of Arrangement. Compensation expense of $0.52 million was recorded as non-cash general and administrative expense for all stock options granted on or after January 1, 2003, with a corresponding amount recorded as contributed surplus. For stock options granted prior to January 1, 2003, the pro forma earnings impact of related stock-based compensation expense is disclosed (see note 10).

Foreign Currency

Effective January 1, 2002, the Company retroactively adopted the CICA amended accounting standard with respect to accounting for foreign currency translation. As a result of the amendments, all exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recognized in income. Previously, these exchange gains and losses were deferred and amortized over the remaining life of the monetary item. The impact of the amended standard on the year ended December 31, 2002 was to increase net income by $1.8 million. The effect of this change on the December 31, 2001 Consolidated Balance Sheet is an elimination of the unrealized foreign exchange loss of $13.7 million, a decrease in future income taxes of $6.0 million, and an increase in the deficit of $7.7 million.

4. TRANSFER OF ASSETS AND LIABILITIES PURSUANT TO PLAN OF ARRANGEMENT

Under the Plan of Arrangement (note 1), the Company transferred to Crew a portion of the Company's producing and exploratory petroleum and natural gas assets. As this was a related party transaction, assets and liabilities were transferred at carrying value as follows:

Petroleum and natural gas assets and equipment	$	21,244
Future income tax asset		3,278
Total assets transferred		24,522
Provision for future site restoration		(559)
Net assets transferred and reduction in share capital *(note 9)*	$	23,963

Reorganization costs of $18.9 million were expensed in the consolidated statement of operations as a result of the Plan of Arrangement.

5. PETROLEUM AND NATURAL GAS PROPERTIES

As at December 31	2003	2002
Petroleum and natural gas properties	$ 2,016,382	$ 1,989,246
Accumulated depletion and depreciation	(1,173,249)	(1,056,930)
	$ 843,133	$ 932,316

During 2003, $4.4 million (2002 – $6.7 million) of corporate expenses relating to exploration and development activities were capitalized. No corporate expenses have been capitalized since the inception of operations as a trust effective September 2, 2003. In calculating the depletion and depreciation provision for 2003, $51.1 million (2002 – $80.3 million) of costs relating to undeveloped properties and materials and supplies of $4.0 million (2002 – $5.5 million) were excluded from costs subject to depletion and depreciation.

6. BANK CREDIT FACILITIES

On September 3, 2003, the Company entered into a new credit agreement with a syndicate of chartered banks. The credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The facilities aggregating $165 million are subject to semi-annual review beginning in November 2003 and are secured by a floating charge over all of the Company's assets. At December 31, 2003, there were no amounts outstanding under the bank credit facilities.

7. LONG-TERM DEBT

As at December 31	2003	2002
Senior secured notes (2002 – US$57,000,000)	$ –	$ 90,037
10.5% senior subordinated notes (2003 – US$247,000; 2002 – US$150,000,000)	319	236,940
9.625% senior subordinated notes (2003 – US$179,699,000)	232,243	–
	$ 232,562	$ 326,977

Senior Secured Notes

On November 13, 1998, the Company issued US$57 million of senior secured notes, bearing interest at 7.23 percent payable quarterly with principal repayable on November 13, 2004. In May 2003, the Company redeemed the outstanding senior secured notes for a total cash payment of $90 million, resulting in a cost of $4.7 million on the redemption. Foreign exchange gains were included in income until the redemption of the notes.

Senior Subordinated Notes

On February 12, 2001, the Company issued US$150 million of senior subordinated notes ("Old Notes") bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities.

On July 9, 2003, the Company completed an exchange offer related to its Old Notes. The Company issued US$179.7 million of 9.625 percent senior subordinated notes due July 15, 2010 ("New Notes") in exchange for US$149.8 million of the Old Notes and incurred a non-cash loss of $40.0 million on the completion of this transaction, which was recognized in income. The New Notes are unsecured and are subordinate to the Company's bank credit facilities.

Interest Expense

The Company has incurred interest expense on its outstanding debt as follows:

	2003	2002
Bank loan	$ 675	$ 760
Amortization of deferred charges	1,027	1,052
Long-term debt	21,846	23,405
Total interest	$ 23,548	$ 25,217

8. DEFERRED CREDITS

As at December 31	2003	2002
Deferred interest swap settlement	$ –	$ 12,181

In August 2002, the Company terminated all outstanding interest rate swap agreements for total proceeds of $14.1 million. This amount was deferred and was being amortized as a reduction of interest expense over the original terms of the agreements. The amortization was terminated when the senior secured notes were redeemed and when the exchange offer related to the Old Notes was concluded (note 7). The residual balance was included in the cost on redemption and exchange of notes.

9. UNITHOLDERS' CAPITAL AND EXCHANGEABLE SHARES

Trust Units

The Trust is authorized to issue an unlimited number of trust units. Pursuant to the Plan of Arrangement, 53,304,858 trust units and 4,732,326 exchangeable shares were issued on September 2, 2003 on the exchange of the common shares of the Company.

On December 12, 2003, the Trust issued 6,500,000 trust units at $10.00 per unit for gross proceeds of $65 million pursuant to a prospectus.

Trust Units	Number of Units	Amount
Issued September 2, 2003 pursuant to Plan of Arrangement	53,305	$ 377,419
Issued on conversion of Exchangeable Shares	1,016	7,135
Unit-based compensation	–	515
Issued for cash, net of expenses	6,500	61,525
Balance December 31, 2003	60,821	$ 446,594

Exchangeable Shares

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either cash or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the weighted average trust unit price of the five-day trading period ending on the record date. The exchange ratio at December 31, 2003 was 1.04530 trust units per exchangeable share. Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded.

Exchangeable Shares	Number of Shares	Amount
Issued September 2, 2003 pursuant to Plan of Arrangement	4,732	$ 33,507
Exchanged for trust units	(1,007)	(7,135)
Balance December 31, 2003	3,725	$ 26,372

Under the Plan of Arrangement, shareholders of the Company received one unit of the Trust or one exchangeable share and one third of a share of Crew for each common share held.

Common shares of Baytex Energy Ltd.	Number of Shares	Amount
Balance December 31, 2001	52,008	$ 394,734
Exercise of stock options	820	3,497
Normal course issuer bid	(9)	(55)
Balance December 31, 2002	52,819	398,176
Flow-through shares issued	103	810
Future tax related to flow-through shares	–	(336)
Exercise of stock options *(note 10)*	5,115	36,239
Transfer of assets under Plan of Arrangement *(note 4)*	–	(23,963)
Balance September 2, 2003 prior to Plan of Arrangement	58,037	410,926
Trust units issued	(53,305)	(377,419)
Exchangeable shares issued	(4,732)	(33,507)
Balance December 31, 2003	–	$ –

Flow-through Shares

In accordance with the terms of flow-through share offerings entered into by the Company and pursuant to certain provisions of the *Income Tax Act* (Canada), the Company fulfilled its commitment to renounce for income tax purposes exploration expenditures of $0.8 million in 2003 to the subscribers of the flow-through shares.

10. TRUST UNIT RIGHTS AND STOCK OPTIONS

Effective September 2, 2003, the Trust established a Trust Unit Rights Incentive Plan to replace the stock option plan of the Company. A total of 5,800,000 Trust Unit Rights are reserved for issue under the plan. Trust Unit Rights are granted at the market price of the trust units at the time of the grant, vest over three years and have a term of five years.

The Trust Unit Rights Incentive Plan allows for the exercise price of the rights to be reduced in future periods by a portion of the future distributions provided a certain threshold return on assets is met. The Trust has determined that the amount of the reduction cannot be reasonably estimated, as it is dependent upon a number of factors including, but not limited to, future trust unit prices, production of oil and natural gas, determination of amounts to be withheld from future distributions to fund capital expenditures, and the purchase and sale of oil and natural gas assets. Therefore, it is not possible to determine a fair value for the rights granted under the plan.

Compensation expense is therefore determined based on the amount that the market price of the trust unit exceeds the exercise price for rights issued as at the date of the consolidated financial statements and is recognized in income over the vesting period of the plan. The adoption of the amendments related to accounting for unit-based compensation results in compensation expense for the year ended December 31, 2003 of $0.22 million (note 3).

The number of unit rights issued and exercise prices are detailed below:

	Number of Rights	Weighted Average Exercise Price[1]
Initial grant September 9, 2003	2,593	$ 10.23
Granted	380	$ 9.60
Cancelled	(118)	$ 10.23
Balance December 31, 2003	2,855	$ 10.15

(1) Exercise price reflects grant prices less reduction in exercise price as discussed above.

The following table summarizes information about the unit rights outstanding at December 31, 2003:

	Number Outstanding at December 31, 2003	Weighted Average Remaining Term (years)	Weighted Average Exercise Price	Number Exercisable at December 31, 2003	Weighted Average Exercise Price
Balance December 31, 2003	2,855	4.7	$ 10.15	–	$ –

The Company had a stock option plan prior to the Plan of Arrangement. The outstanding stock options of the Company were exercised or cancelled as follows:

	Number of Options	Weighted Average Exercise Price
Balance December 31, 2002	5,126	$ 6.98
Granted	121	$ 9.28
Exercised	(5,115)	$ 7.07
Cancelled	(132)	$ 5.44
Balance December 31, 2003	–	$ –

The adoption of the amendments related to accounting for unit-based compensation also impacted the accounting for stock options granted by the Company to employees before the implementation of the Plan of Arrangement. Compensation expense of $0.52 million was recorded as non-cash general and administrative expense for all stock options granted by the Company on or after January 1, 2003, with a corresponding amount recorded as trust units on exercise of the options, with expenses in the first and second quarters increased by $0.32 million and $0.20 million, respectively. Accordingly, quarterly net income in such quarters previously reported as $32.9 million and $41.8 million would be revised to $32.6 million and $41.6 million, respectively. There were no changes to the expenses or the net loss of the third quarter of 2003.

Compensation expense for options granted during 2003 was based on the estimated fair values at the time of the grant and the expense was recognized over the vesting period of the option. For options granted prior to January 1, 2003, the pro forma earnings impact of related stock-based compensation expense is as follows:

Year Ended December 31	2003	2002
Net income as reported	**38,138**	45,136
Stock-based compensation expense	**(5,522)**	(612)
Pro forma	**32,616**	44,524
Net income per unit		
Basic as reported	**0.69**	0.86
Pro forma	**0.59**	0.85
Diluted as reported	**0.67**	0.85
Pro forma	**0.68**	0.83

The weighted average fair market value of options granted during the year ended December 31, 2003 was $4.21 per option (2002 – $3.65 per option). The fair value of the stock options granted was estimated on the grant date based on the Black-Scholes option-pricing model using the following assumptions: risk-free interest rate of 4.5 percent; expected life of four years; and expected volatility of 52 percent.

11. NET INCOME PER UNIT

The Trust applies the treasury stock method to assess the dilutive effect of outstanding trust unit rights on net income per unit. The exchangeable shares outstanding at year-end, converted at the year-end exchange ratio, have been included in the calculation of the weighted average number of trust units outstanding:

	2003	2002
Weighted average number of units (shares) outstanding	53,955	52,298
Trust units issuable on conversion of exchangeable shares	1,535	–
Weighted average number of units (shares) outstanding, basic	55,530	52,298
Dilutive effect of trust unit incentive rights (stock options)	990	939
Weighted average number of units (shares) outstanding, diluted	56,520	53,237

The dilutive effect of trust unit incentive rights above did not include 2.7 million trust unit rights (2002 – 2.8 million stock options) because the respective exercise prices exceeded the average market price of the trust units during the year.

12. INCOME TAXES (RECOVERY)

The provision for (recovery of) income taxes has been computed as follows:

	2003	2002
Income before income taxes	$ 34,170	$ 92,808
Expected income taxes at the statutory rate of 42.5% (2002 – 44.0%)	$ 14,526	$ 40,743
Increase (decrease) in taxes resulting from:		
Crown royalties	21,451	21,153
Resource allowance	(18,334)	(26,308)
Alberta royalty tax credit	(213)	(219)
Net income of the Trust	(14,191)	–
Non-taxable portion of foreign exchange gain	(11,074)	–
Rate change	(6,216)	(138)
Non-cash general and administrative	314	–
Other	106	2,725
Large corporation tax and provincial capital tax	9,663	9,716
Provision for (recovery of) income taxes	$ (3,968)	$ 47,672

The components of future income taxes are as follows:

As at December 31	2003	2002
Future income tax liabilities:		
Capital assets	$ 200,526	$ 202,429
Other	2,560	–
Future income tax assets:		
Provision for future site restoration	(8,907)	(9,638)
Reorganization costs	(19,794)	(2,833)
Loss carry-forward	–	(323)
Other	–	(5,233)
Future income taxes	$ 174,385	$ 184,402

13. CASH FLOW INFORMATION

Increase (Decrease) in Non-Cash Working Capital Items

	2003	2002
Current assets	$ (1,840)	$ 38,528
Current liabilities	(12,435)	28,229
	$ (14,275)	$ 66,757

	2003	2002
Changes in non-cash working capital related to:		
Operating activities	$ (8,060)	$ 1,272
Investing activities	(6,215)	65,485
	$ (14,275)	$ 66,757

During the year, the Trust made the following cash outlays in respect of interest expense and current income taxes.

	2003	2002
Interest	$ 24,449	$ 25,482
Current income taxes (refund)	$ 12,557	$ (3,298)

14. FINANCIAL INSTRUMENTS

The Trust's financial instruments recognized in the balance sheet consist of cash and short-term investments, accounts receivable, current liabilities and long-term borrowings. The estimated fair values of the financial instruments have been determined based on the Trust's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction.

The fair values of financial instruments other than long-term borrowings approximate their carrying amounts due to the short-term maturity of these instruments. At December 31, 2003, the trading value of the Company's senior subordinated term notes was 105 percent in relation to par (2002 – 105 percent).

15. DERIVATIVE CONTRACTS

The nature of the Trust's operations results in exposure to fluctuations in commodity prices, exchange rates and interest rates. The Trust monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts. In 2003, petroleum and natural gas sales were reduced by $33.8 million (2002 – $8.3 million) due to derivative contracts.

At December 31, 2003, the Trust had derivative contracts for the following:

Oil	Period	Volume	Price	Index
Price collar	Calendar 2004	5,000 bbls/d	US$24.00 – $28.60	WTI
Price collar	Calendar 2004	1,500 bbls/d	US$24.00 – $29.05	WTI
Price collar	Calendar 2004	1,500 bbls/d	US$24.00 – $29.08	WTI
Price collar	Calendar 2004	1,000 bbls/d	US$24.00 – $29.38	WTI
Price collar	Calendar 2004	1,000 bbls/d	US$24.00 – $29.48	WTI
Price collar	Calendar 2004	2,000 bbls/d	US$24.00 – $30.55	WTI
Price collar	Calendar 2004	3,000 bbls/d	US$24.00 – $32.05	WTI

The fair value of the oil derivative contracts at December 31, 2003 is an unrecognized liability of $13.8 million.

Foreign currency	Period	Amount	Exchange Rate Floor	Cap
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3100	CAD/USD $1.3400
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3280	CAD/USD $1.3560
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3160	CAD/USD $1.3365
Collar	Calendar 2004	US$3,000,000 per month	CAD/USD $1.3400	CAD/USD $1.3665

The fair value of the foreign currency contracts at December 31, 2003 is an unrecognized asset of $3.7 million.

Interest rate swap	Period	Principal	Rate
	November 2003 to July 2010	US$197,669,000	3-month LIBOR plus 5.2%

The fair value of the interest rate swap at December 31, 2003 is an unrecognized asset of $3.9 million.

16. COMMITMENTS AND CONTINGENCIES

In October 2002, the Trust entered into a long-term crude oil supply contract with a third party that requires the delivery of up to 20,000 barrels per day of Lloydminster Blend crude oil at a price fixed at 71% of NYMEX WTI oil price. The contract is for an initial term of five years commencing January 1, 2003. The contract volumes increased from 9,000 barrels per day in January 2003 to 20,000 barrels per day in October 2003 and thereafter.

For the period November 2003 to March 2004, the Trust has entered into natural gas physical sales contracts with third parties for a total of 9.5 mmcf per day for prices collared between $5.28 and $8.57 per mcf. For the period April 2004 to October 2004, the Trust has entered into natural gas physical sales contracts with third parties for a total of 9.5 mmcf per day for prices collared between $4.75 and $6.75 per mcf.

The Trust is engaged in litigation and claims arising in the normal course of operations, none of which could reasonably be expected to materially affect the Trust's financial position or reported results of operations.

Under the Net Profits Interests Agreement between the Company and the Trust, the Company will establish in 2004 a reclamation fund to fund the payment of environmental and site restoration costs.

17. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The consolidated financial statements have been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP"), which differ in some respects from GAAP in the United States. The significant differences in GAAP, as applicable to these consolidated financial statements and notes, are described in the Trust's Form 40-F, which is filed with the United States Securities and Exchange Commission.

The Board of Directors and management of Baytex Energy Ltd. ("Baytex") is committed to ensuring proper corporate governance practices for both Baytex and Baytex Energy Trust (the "Trust") and continues to seek ways to enhance the Board's ability to guide the Company in today's dynamic corporate environment. Baytex and the Trust intends to comply with all applicable regulations with a goal of providing transparency in our corporate governance practices.

In 1995, the Toronto Stock Exchange ("TSX") published a set of guidelines (the "Guidelines"), which were revised in 1999, relating to corporate governance. The Guidelines address such matters as the constitution and the independence of boards of directors, the functions to be performed by boards and their committees and the relationships between the board, management and shareholders. The Board of Baytex has developed systems and procedures that are aligned with the Guidelines and are appropriate for Baytex and the Trust.

Mandate of the Board of Baytex Energy Ltd. The Board is responsible for the stewardship of Baytex, the Trust and other subsidiaries. In discharging its responsibility, the Board exercises the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances and acts honestly and in good faith with a view to the best interests of the Trust. The Board's mandate includes: the review and approval of strategic, operating, capital and financial plans; the identification of the principal risks of the Trust's business and the review of risk management systems; the appointment and review of the officers of Baytex; the approval of communication policies and the integrity of the Trust's internal financial controls and management systems; the acquisition and disposition of properties; the approval of capital expenditure budgets; the establishment of credit facilities; the issue of trust units and distribution policies.

The Board holds regularly scheduled quarterly meetings to review the business affairs of Baytex and the Trust. The Chairman of the Board is not a member of management and has a separate role from the President and CEO of Baytex.

Board Composition The Baytex board is currently comprised of six members, all of whom are unrelated directors except for the Chief Executive Officer within the meaning of the current TSX Guidelines.

Committees The Board of Directors has established an Audit Committee, a Reserve Committee and a Compensation Committee. All the committees are comprised of unrelated directors and report to the Board of Directors of Baytex.

Audit Committee The Audit Committee is currently comprised of three unrelated directors, all of which are financially literate. The Audit Committee is responsible for oversight of the nature and scope of the annual audit, management's reporting of internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for board approval, the audited financial statements and other mandatory disclosure releases containing financial information.

Reserve Committee The Reserve Committee is responsible for reviewing the independence of the engineering firm performing the annual reserve evaluation and their final reserve report. The Committee is made up of three unrelated directors of which all three possess the technical knowledge necessary to perform their duties under this committee.

Compensation Committee The Compensation Committee is responsible for the review of compensation matters for the officers and employees of the Trust including the Chief Executive Officer.

Baytex Energy Trust commenced operations as an oil and gas income trust on September 2, 2003. As the Trust is the successor organization to Baytex Energy Ltd., results of the current period may not be entirely comparable to those of the prior periods as certain assets were transferred out of Baytex pursuant to the Plan of Arrangement effective September 2, 2003.

Financial *($ thousands, except per share amounts)*	2003	2002	2001	2000	1999
Petroleum and natural gas sales	$ 357,404	$ 365,860	$ 329,700	$ 286,226	$ 120,238
Cash flow from operations(1)	138,233	191,086	144,070	155,326	62,703
Per unit/share – basic	2.49	3.65	2.91	3.68	1.77
Cash distributions paid or declared	33,382	–	–	–	–
Per unit	0.60	–	–	–	–
Net income (loss)	38,138	45,136	(137,107)	41,682	16,485
Per unit/share – basic	0.69	0.86	(2.77)	0.99	0.47
Capital expenditures, net	49,263	126,468	375,853	388,052	73,243
Total net debt	213,572	362,775	379,061	256,257	136,629
Total assets	959,136	997,760	967,046	829,227	419,163
Operations					
Production					
Light oil and NGLs (bbls/d)	2,273	3,154	5,152	4,107	4,457
Heavy oil (bbls/d)	23,911	23,967	26,533	20,005	5,574
Total oil and NGLs (bbls/d)	26,184	27,121	31,685	24,112	10,031
Natural gas (mmcf/d)	63.0	72.6	70.8	57.7	56.1
Barrels of oil equivalent (boe/d @ 6:1)	36,686	39,214	43,488	33,721	19,381
Reserves(2)					
Crude oil and NGLs (mbbls)					
Proved	63,148	104,584	110,221	105,022	56,420
Probable	25,369	25,637	26,167	24,019	18,528
Total	88,517	130,221	136,388	129,041	74,948
Natural gas (mmcf)					
Proved	81,575	75,573	134,653	98,048	103,947
Probable	24,275	13,521	21,384	15,101	23,802
Total	106,300	89,094	156,037	113,149	127,749
Wells drilled (gross)					
Oil	173	106	63	267	109
Gas	67	51	81	28	28
Other	7	3	3	4	1
Dry	19	26	32	23	25
Total	266	186	179	322	163

(1) Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other operating items. The Trust's cash flow from operations may not be comparable to other companies. The Trust considers cash flow a key measure of performance as it demonstrates the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.

(2) Reserves information from 1999 to 2002 is prepared in accordance with National Policy 2-B. Probable reserves presented herein for those years represents 50 percent of the total probable reserves then assigned to allow more appropriate comparison with probable reserves under NI 51-101 as at January 1, 2004.

CORPORATE INFORMATION

BOARD OF DIRECTORS

John A. Brussa
Partner
Burnet, Duckworth & Palmer LLP

W.A. Blake Cassidy
Retired Banker

Raymond T. Chan
President and CEO
Baytex Energy Trust

Edward Chwyl
Independent Businessman

Naveen Dargan
Independent Businessman

Dale O. Shwed
President and CEO
Crew Energy Inc.

OFFICERS

Raymond T. Chan
President and CEO

Daniel G. Belot
Vice President, Finance and CFO

Randal J. Best
Vice President, Corporate Development

Ralph W. Gibson
Vice President, Marketing

Richard W. Naden
Vice President, Engineering and Operations

Shannon M. Gangl
Secretary
Partner
Burnet, Duckworth & Palmer LLP

HEAD OFFICE

Suite 2200, Bow Valley Square II
205 – 5th Avenue S.W.
Calgary, Alberta T2P 2V7
Phone: 403-269-4282
Fax: 403-205-3845
Website: www.baytex.ab.ca
Toll-free: 1-800-524-5521

AUDITORS

Deloitte & Touche LLP

BANKERS

The Toronto-Dominion Bank
BNP Paribas (Canada)
National Bank of Canada
Union Bank of California
Royal Bank of Canada

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Associates Limited

TRANSFER AGENT

Valiant Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Stock Symbol: BTE.UN

ABBREVIATIONS

bbls	barrels
bbls/d	barrels per day
bcf	billion cubic feet
boe	barrels of oil equivalent (6 mcf: 1 bbl)
mbbls	thousand barrels
mmbbls	million barrels
mboe	thousand barrels of oil equivalent
mmboe	million barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGLs	natural gas liquids

ADVISORY

Certain statements in this report are "forward-looking statements" within the meaning of the *United States Private Securities Litigation Reform Act of 1995*. Specifically, this report contains forward-looking statements relating to Management's approach to operations, expectations relating to the number of wells, amount and timing of capital projects, foreign exchange rates, interest rates, worldwide and industry production, prices of oil and gas, heavy oil differentials, company production, cash flow and debt levels. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies; fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the result of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the imprecision of reserve estimates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and gas operations; the weather in the Trust's areas of operations; and other factors, many of which are beyond the control of the Trust. There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

BAYTEX

ENERGY TRUST

Suite 2200, Bow Valley Square II
205 – 5th Avenue S.W., Calgary, Alberta T2P 2V7
www.baytex.ab.ca